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Project Milestone and Deliverable Accomplishments

Task No.	Milestone/Deliverable	Scheduled Date	Completed Date	Milestone
3.1.7	First Quarterly Status Report	6/30/2005	7/15/2005	MS
3.1.8	Preliminary Report on Wet Gas ICDA	8/31/2005	8/31/2005	MS
3.1.7	Second Quarterly Status Report	10/15/2005	10/14/2005	MS
3.1.7	Third Quarterly Status Report	1/15/200	1/13/2006	MS
3.1.7	Fourth Quarterly Status Report	4/15/2006	4/19/2006	MS
3.1.8	Final Proposed Standard on Wet Gas ICDA	4/30/2006	5/15/2006	MS
3.1.7	Final Report	6/30/2006	2/15/2007	MS

Results and Conclusions

This project has significantly accelerated development of the wet gas internal corrosion direct assessment (ICDA) standard. Within six months, a preliminary document outlining a proposed standard on wet gas ICDA was completed. This document was submitted to the NACE (National Association of Corrosion Engineers) committee members for review and comments. The comments received and further developments toward the standard were included in an updated draft of the proposed standard for discussion at the NACE Corrosion 2006 Conference in February 2006. Further revisions were made to the draft following this conference. A final draft proposed standard on wet gas ICDA was submitted to the DOT PHMSA in April 2006 for comment. DOT PHMSA comments were incorporated into the April 2006 proposed standard for wet gas ICDA that is included in this Final Report.

Plans for Future Activity

Although the proposed standard contained herein represents the final report and deliverable for Contract DTPH56-05-T-0002 with DOT PHMSA, it is not sufficiently developed to warrant its consideration for the ballot before NACE. Discussions during NACE's Task Group 305 meeting at the Corrosion 2006 Conference indicated that additional work is required in several key areas in order to fully develop this draft and a wet gas ICDA standard for industry.

One area requiring further development is the development and calibration of a simple model that can prioritize all sub-zones in a region based on the possibility of internal wall loss. Such a simple, expert-based methodology does not rely on complex computer models as these models may not be useable under realistic pipeline scenarios and may not gain acceptance by the broad majority of committee members. One advantage of such a simplified methodology is its ability to establish safety guidelines while permitting flexibility for the users of the standard.

To develop a simplified methodology initially requires detailed calculations of flow and corrosivity. Using the results of these calculations, simple models will be developed whose results will be able to reproduce those obtained from the detailed calculations. Such models will be used to provide qualitative information on pipe wall loss at different sub zones. This approach is similar to that used for dry gas ICDA, where a complex computer code was used to derive a simple parameter to predict critical inclination angles. For either detailed calculations or a simplified model, an understanding of the fundamental principles that govern processes of flow and corrosion are required. The effects of mitigation and transient operations will be integrated into the simple models based on the significance of their effects. Due to the complexity of the process, it is expected that these effects can only be determined qualitatively.

These simple models must be translated into practical guidelines for the standard. Therefore, the models developed must consist of parameters that are readily obtainable from pipeline operations.

Date Prepared: 2006-6-5
TG 305

PROPOSED NACE STANDARD PRACTICE

"Wet Gas Internal Corrosion Direct Assessment Methodology for Pipelines (WG-ICDA)"

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Foreword

This standard practice formalizes an integrity methodology for pipelines or other piping that normally carries natural gas with condensed water or with water and liquid hydrocarbons, termed wet gas internal corrosion direct assessment (WG-ICDA). WG-ICDA is intended to cover pipelines, onshore and offshore, and drips that are operating in natural gas storage and gathering systems in which the liquid to gas ratio is small (i.e., less than 10% in volume). This standard is intended for use by pipeline operators and others who manage pipeline integrity both onshore and offshore normally under wet loading conditions which are beyond the application of NACE Dry Gas ICDA[1] and Liquid ICDA[2].

Direct Assessment (DA) methods have been developed to meet the need for pipeline operators to assess the integrity of pipelines with respect to corrosion. It is a method to prioritize the likelihood of corrosion along a pipeline segment. The goal is to identify locations most likely to have the maximum internal corrosion damage within the pipeline segment. The locations with the greatest likelihood of severe corrosion, including growth rate, and influencing factors such as flow, inhibitor/biocide, solids, upsets, among others, should be excavated and examined. The results of these examinations are used as a basis for assessing the condition and integrity of the remaining pipeline segments (i.e., with less likelihood of corrosion). DA does not depend on the ability of a pipeline to be pigged (i.e., in-line inspected) or pressure tested, making it most valuable to those pipelines that cannot accept pigs or be hydrotested.

For wet gas systems, all sections of the pipelines may possibly accumulate liquid water or liquid water and liquid hydrocarbons. The propensity to accumulate liquids can be determined from a phase diagram for dew point under flow conditions using local temperature, pressure and gas composition. Depending on flow conditions (velocity, gas quality, temperature pressure, wall surface conditions, etc.), in some sections the liquid could flow in the pipeline until full, and then carry over to the next downstream section. In addition, as the liquid continuously travels along the pipe between accumulation points, the effects of flow regimes need to be considered. A pipeline with non-steady flow rates over time must be assumed to have water at all uphill inclinations at some time, and downhill locations cannot be assumed to have low exposure time to water.

The goal of WG-ICDA is to identify locations of most likely internal corrosion damage by integrating available historical information, in combination with the use of flow models, to determine flow regimes, corrosion growth rate models to determine corrosion rate if possible, and rate-influencing factors such as inhibitor/biocide, solids, upsets, low and abnormally high flow and others, to determine their overall total corrosion severity after the methodology techniques of Kent Muhlbauer[3]. The essential focus is the discrimination of conditions along the length of a pipeline so that possible local integrity threats with respect to internal corrosion are identified for prioritized damage repair/mitigation. WG ICDA emphasizes damage distribution over absolute corrosion rate, but the corrosion rate models can fit into the overall process by serving as a tool whenever possible to predict wall losses within one flow pattern such as stratified, slugging, or annular. Because detailed flow and corrosion modeling are cumbersome, abstracted models that are simple to use and can provide guidance to rank severity of different pipeline locations are more desirable.

To prioritize susceptibility to internal corrosion along a pipeline segment, the factors affecting corrosion damage can be separated into six factors[4-5]:

1. Pipeline history. Collect and organize information as detailed as possible for a pipeline segment such as: pre-corrosion, existing defect, product carried previously, operation history, pipeline design considerations, etc.
2. Flow effects. Determine, using thermodynamic and hydrodynamic models, the state and condition of fluids including temperature and pressure profiles, superficial gas and liquid velocities, flow patterns, liquid hold up, etc.
3. Corrosivity. Determine the corrosive potential of the fluid based on gas quality, temperature, pressure, liquid chemistry such as pH and presence of electrolyte.
4. Mitigation. Collect and organize information related to prior mitigation techniques such as inhibition (batch and continuous, oil soluble and water dispersible), biocide treatments, cleaning pigs, internal coatings which have influenced the location and rate of corrosion.

5. Upsets. Document flow situations where the pipeline operation differs from normal or steady state and occurs over various periods of time, and
6. Other factors. Collect and organize other corrosion influences such as hydrocarbon condensates (including emulsion characteristics), sphering, glycol, bacteria, solids/scale, and compressor oil.

Each different flow regime within a given WG-ICDA region will be considered a zone. One zone may consist of pipe segments with different corrosion conditions. The segments, which may be discontinuous, with similar corrosion conditions, are considered to be sub-zones.

The WG-ICDA method consists of the following four standard steps:
1) Pre-Assessment: Collect essential historical and current operating data about the pipeline relevant to corrosion distribution, determine if WG-ICDA is feasible, and define and bound WG-ICDA regions. The types of data to be collected are typically available in design and construction records, operating and maintenance histories, alignment sheets, corrosion survey records, gas and liquid analysis reports, and inspection reports from prior integrity evaluations or maintenance actions. This first step is aimed at understanding the system to be analyzed and classifying the pipeline into regions based on input, withdrawal or processing. Within a region, self-similar flow regimes are defined as zones, and within a zone, the relative corrosion behavior can be assessed with similar corrosion mechanisms and influencing factors characterized as sub-zones. See Figure 3 for visual definition of region, zone and sub-zone.

2) Indirect Examination: Calculations are performed using flow models to determine flow regimes and following the methodology principles of Kent Muhlbauer[3] to weigh, as appropriate, six corrosion-influencing factors to determine the overall corrosivity of each corrosion-susceptible location along a pipeline segment the sub-zones. The sub-zones are prioritized by combining data on the historical performance and five other factors with the end goal of prioritizing the excavation locations for WG-ICDA.

The proposed basis of WG-ICDA is to separate the factors of flow, corrosivity, mitigation, upsets and other corrosion damage influencing factors for easier assessment. Flow effects include possible flow regimes and condensing water (i.e., at locations of heat loss). Expected possible flow regimes are stagnant, stratified, and slugging. On this basis, a pipeline with similar flow effects (e.g., flow regime, velocity) throughout an entire segment is considered to have corrosion distribution determined only by non-flow related corrosivity factors (i.e., gas quality, inhibitors, etc.). However, pipelines with more than one flow regime over a distance can have a corrosion distribution affected by the flow regime.

This standard covers internal corrosion related to the transport of natural gas containing CO_2, H_2S, and/or O_2 together with 1) liquid water containing corrosive species typically found in produced or condensed waters associated with natural gas production, storage and transportation; 2) micro-organisms that may influence corrosion; 3) solids such as deposits or scale; and 4) hydrocarbon liquids. This standard may be applicable to other corrosion mechanisms if technical justification is documented.

Corrosivity depends primarily on product quality, liquid chemistry, pressure, temperature, etc. Although the operational factors such as flow, mitigation, upset and other can have a significant effect on corrosion, they are not defined for corrosivity in this standard. However, the likelihood of finding corrosion damage at a particular location along a pipeline segment is influenced by all of the factors and depending on the pipeline location and history, among others, each is considered in turn and in terms of its overall importance and effect on corrosion distribution.

Region start and finish locations are based on input, and withdrawal or processing. Flow modeling determines the zones which have similar flow, and finally, each zone is separated into sub-zones based on and the six influencing factors. For each sub-zone in all zones and regions of a pipeline segment of interest for DA, a weight factor is assigned to each of the other five major corrosion-influencing factors, based on an expert's opinion of their relative importance: history, corrosivity, mitigation, upsets or other operational factors. Through a pre-determined formula, a subtotal corrosivity of each sub-zone can be obtained within a zone. For different zones, the flow effect can influence the corrosivity of a sub-zone. The methodology will estimate the total corrosivity of each sub-zone including the effect of flow. Since the duration or interval of factors in a sub-zone corrosion has a proportional effect on corrosivity, the interval must be used to develop the total corrosivity prediction of each sub-zone within all regions of a pipeline segment. The overall total corrosivity of each sub-zone will be ranked for all sub-zones in all regions, and prioritization of the sub-zones can be separated into high, medium or low levels of a corrosion integrity threat. The detailed description of the above ranking process to arrive at a prioritized dig list is given in Appendix A. An example is also provided.

3) Direct (or Detailed) Examinations: The pipe is excavated and examined at locations that have been identified and prioritized by the previous two steps. The pipe examination must have sufficient detail to determine the existence, extent, and severity of internal corrosion. Examination of the internal surface of a pipe can involve non-destructive examination methods sufficient to identify and characterize internal defects. Bayesian updating (Appendix B) may be used to incorporate inspection information (e.g., in-line, excavation, etc.) and update the determination of most damage locations for sub-zones. This provides a systematic method for focusing costly inspections only on those locations with the highest possible damage and incorporating the results of the inspection in a manner that improves confidence in future determinations.

4) Post-Assessment: Analysis of the indirect and direct examination data is performed to confirm the overall pipeline integrity, prioritize scheduled repairs, set the interval for the next assessment, activate mitigation, control and maintenance strategies, and assess the effectiveness of WG-ICDA. If the results of excavations do not match the original prediction of most likely locations of internal corrosion, the weighting method for overall total corrosivity of sub-zones in Step 2 needs to be re-evaluated and or updated. The updating strategy can be operator specific and may involve adjustment of the weighting formula or the values assigned to each weight factor to result in improved matching with excavation data.

Note that this standard provides an alternative to steps two and three and provides for a 100% detailed internal inspection of the excavated pipe, providing the segment is short and/or flow modeling is rather sophisticated and expensive. In this case, the pre-assessment and post assessment requirements remain and need to be fully completed to meet the intent of this WG-ICDA methodology.

This standard was prepared by Task Group (TG) 305 on Internal Corrosion Direct Assessment for Wet Gas Pipelines. TG 305 is administered by Specific Technology Group (STG) 35 on Pipelines, Tanks, and Well Casings. This standard is issued by NACE International under the auspices of STG 35.

In NACE standards, the terms *shall*, *must*, *should*, and *may* are used in accordance with the definitions of these terms in the NACE Publications Style Manual, 4th ed., Paragraph 7.4.1.9. *Shall* and *must* are used to state mandatory requirements. The term *should* is used to state something good and is recommended but is not mandatory. The term *may* is used to state something considered optional.

Section 1: General

1.1 Introduction

1.1.1 This standard covers the NACE ICDA process for wet natural gas pipeline systems. This standard is intended to serve as a guide for applying the NACE WG-ICDA process on natural gas pipeline systems that meet the feasibility requirements of Paragraph 3.3 of this standard.

1.1.2 The primary purposes of the WG-ICDA method are: (1) to enhance the assessment of internal corrosion in natural gas pipelines, and (2) to help ensure pipeline integrity.

1.1.3 WG-ICDA was developed for onshore and offshore natural gas pipelines that have water as a normal impurity and expect the water to condense out, and may become trapped by fixtures or designed traps. Because of this, WG-ICDA is applicable to wet gathering and producing pipelines.

1.1.4 One benefit of the WG-ICDA approach is that an assessment can be performed on a pipe segment for which alternative methods (e.g., in-line inspection, hydrostatic testing, etc.) may be impractical.

1.1.5 The basis of WG-ICDA for gas lines is a detailed examination of locations along a pipeline where either the reduction of the pipe wall thickness or the potential corrosion rate goes beyond a level that would pose a threat to the pipeline if mitigation or other measures are not taken before the next assessment. This allows inferences to be made about the remaining downstream length of pipe.

1.1.6 This method involves predicting the locations along a length of pipe that most likely have either the greatest reduction of the pipe wall thickness or potentially highest corrosion severity; other locations are likely to have suffered less corrosion when operating under the same conditions.

1.1.7 The process involves identifying areas in which internal corrosion (or the potential for future internal corrosion) is unacceptable, and conversely, where internal corrosion is acceptable, for incorporation into corrosion integrity and risk management plans.

1.1.8 In the process of applying WG-ICDA, other pipeline integrity threats, such as external corrosion, mechanical damage, stress corrosion cracking (SCC), etc., may be detected. When such threats are detected, additional assessments and/or inspections to address these threats must be performed.

1.1.9 The WG-ICDA methodology assesses the likelihood of internal corrosion and includes existing methods of examination available to a pipeline operator to determine the existence, extent and severity of internal corrosion.

1.1.10 WG-ICDA also uses flow modeling results (dew point, flow velocities, liquid hold-up and flow patterns) and provides a framework to utilize those methods.

1.1.11 WG-ICDA has limitations and not all pipelines can be successfully assessed with WG-ICDA. These limitations are identified in the pre-assessment step.

1.1.12 For accurate and correct application of this standard, it shall be used in its entirety. Using or referring to only specific paragraphs or sections can lead to misinterpretation or misapplication of the recommendations and practices contained herein.

1.1.13 This standard does not designate practices for every specific situation because the complexity of internal conditions may rule out (eliminate) various pipeline systems.

1.1.14 This standard does not address specific remedial actions that may be taken when corrosion is found. However, the reader is referred to ASME B31.8[6] and other relevant documents for guidance. The pipeline operator should utilize appropriate methods to address risks other than internal corrosion, such as those described in NACE International, ASME B31.8,[6] API 1160,[7] ANSI/API 579,[8] and BS 7910[9] standards, international standards, and other documents.

1.1.15 The provisions of this standard shall be applied by or under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and/or related practical experience, are qualified to engage in the practice of corrosion control and risk assessment on pipeline systems. Such persons may be: (1) registered professional engineers, (2) recognized as corrosion specialists by organizations such as NACE International, or (3) professionals (i.e., engineers or technicians) with professional experience including detection/mitigation of internal corrosion and evaluation of internal corrosion on pipelines.

1.2 Four-Step Process

1.2.1 WG-ICDA requires the integration of data from multiple field examinations and internal pipe surface evaluations, including the pipeline's physical characteristics and operating history. A flow chart that illustrates the components of each step is shown in Figure 1.

1.2.2 WG-ICDA includes the following four steps:

1.2.2.1 Pre-assessment collects essential historic and present operating data about the pipeline, determines whether WG-ICDA is feasible, and then defines WG-ICDA like-similar flow regions based on modes of flow. The types of data to be collected are typically available in design and construction records: topography, routes, material, design pressures and temperatures, etc.; operating and maintenance histories, alignment sheets, corrosion survey records, gas and liquid analysis reports, and inspection reports from prior integrity evaluations or maintenance actions.

1.2.2.2 Indirect examination covers techniques used for prediction and prioritization of overall corrosion severity at different locations along a pipeline. This includes determination of regions along a pipeline based on input, withdraw and processing, determination of zones or flow regimes within a region through multiphase flow modeling and determination of sub-zones based on corrosivity and influencing factors. Calculations are performed to prioritize locations along a pipeline for susceptibility to and severity of corrosion damage. For WG-ICDA, the factors contributing to the distribution of corrosion within each flow regime will be identified and the corrosion damage is predicted.

1.2.2.3 Direct examination includes performing excavations and conducting detailed examinations at locations prioritized to have the highest likelihood or potentially severest damage of corrosion. The examination must have sufficient detail to determine the existence, extent, and severity of corrosion. Examination of the internal surface of a pipe can involve non-destructive examination methods sufficient to identify and characterize internal defects. Bayesian updating (Appendix B) may be used to help reprioritize the excavation sites.

1.2.2.4 Post assessment covers analysis of data collected from the previous three steps to assess the effectiveness of the WG-ICDA process, activate and prioritize mitigation, control and maintenance strategies, and determine reassessment intervals. If the results of excavations do not match the original assumption, the corrosion distribution model will be updated to guide the next excavation (i.e., the operator returns to step two or step one depending on the pre-assessed information, see Figure 1). Figure 2 shows a flow chart with each WG-ICDA step.

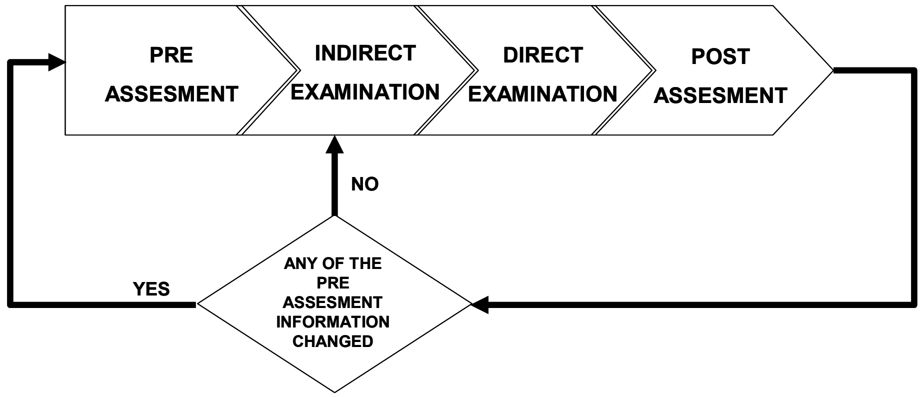


Figure 1. Four steps of WG-ICDA.

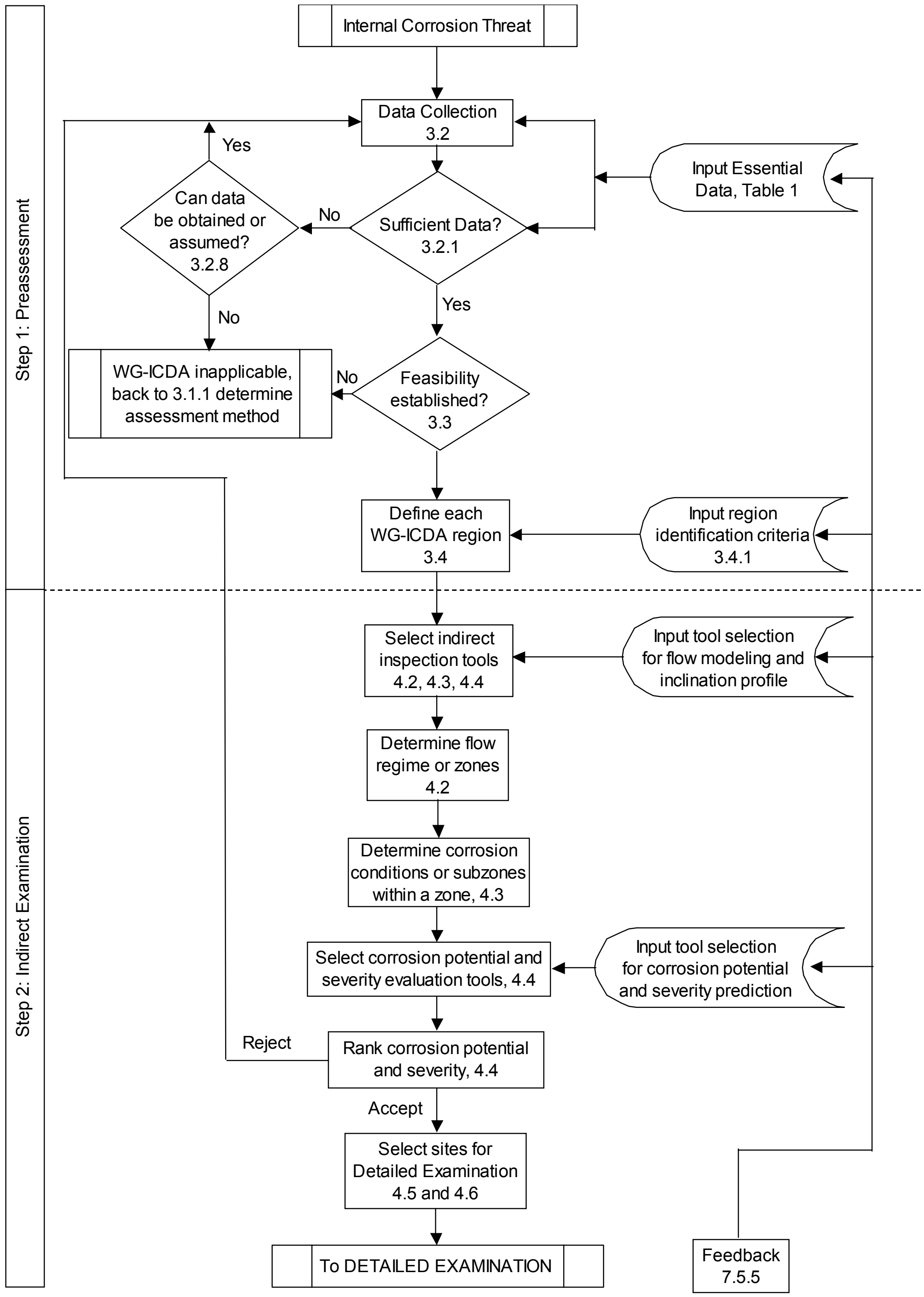


Figure 2: Wet Gas Internal Corrosion Direct Assessment Flowchart –Part 1

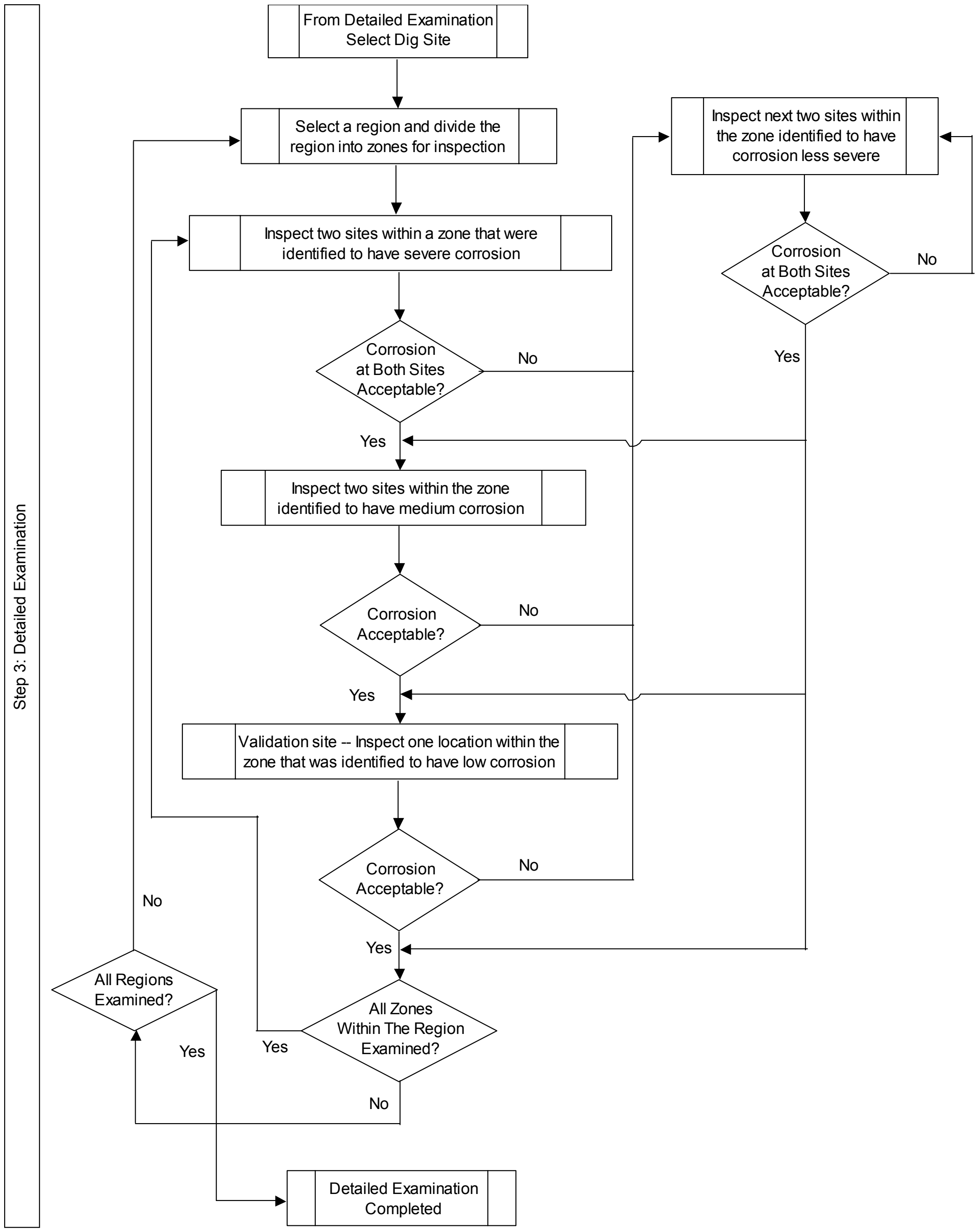


Figure 2: Wet Gas Internal Corrosion Direct Assessment Flowchart –Part 2

Section 2: Definitions

Annular Flow: A multiphase-flow regime in which fluids are separated into concentric layers, with heavier (i.e., higher density) fluids flowing in an annular pattern near the pipe wall and the lighter fluids flowing through the center.

Anomaly: See *Indication*.

Cleaning Pig: A device inserted in a pipeline for cleaning solids out of a pipeline or displacing liquids. A spheroid implement used to displace liquid hydrocarbons from natural gas pipelines.

Corrosion: The deterioration of a material, usually a metal, that results from a reaction with its environment.

Corrosion Mechanism: The nature of a corrosion process whose rate may be controlled by one of, perhaps, multi steps leading to corrosion. In aerated solution, the steel corrosion rate can be under diffusion control, while in deaerated solution, the corrosion rate may be under kinetic control due to water or hydrogen ion reduction. In the case of CO_2 corrosion, due to its slow homogenous hydration step, the corrosion rate can be controlled by the CO_2 hydration step.

Corrosivity: Severity of corrosion depending primarily on product quality, liquid chemistry, pressure, temperature, etc. The effects of operational parameters such as flow, mitigation, upsets, etc. are not considered in the scope of corrosivity.

Coupons: Strips or pieces of metal, which are temporarily placed within a process system for a known period of time. They are examined after cleaning. The change in weight over the exposure period provides a general corrosion rate. By measuring the depth of individual pits, a pitting corrosion rate can be determined. Specialized analyses can be undertaken to better define corrosion mechanisms.

Critical Inclination Angle: Angle determined by DG-ICDA; the lowest angle at which liquid carryover is not expected to occur.

Defined Length: Any length of pipe until a new inlet changes the potential for water entry or flow characteristics.

Detailed Examination: Examination of the pipe wall at a specific location to determine whether metal loss from internal corrosion has occurred. This may be performed using visual, ultrasonic, radiographic, or other means.

Direct Assessment (DA): A pipeline integrity verification method based on prioritizing the likelihood of corrosion along a pipeline segment. The locations with the greatest likelihood of severe corrosion are excavated and examined. The results of these examinations are used as a basis for assessing the condition of the remaining pipeline segment (i.e., with less likelihood of corrosion).

Dry Gas: A gas above its dew point and without condensed liquids.

Dry Gas Internal Corrosion Direct Assessment (DG-ICDA): An internal corrosion direct assessment process applicable to normally dry gas systems. See reference 1.

Electrical Resistance (ER) Probe: When electrical resistance probes are wetted by process fluids, the probe elements will corrode. By measuring the change in electrical resistance over time, a general corrosion rate can be determined, taking into consideration the geometry of the probe element. ER probes cannot be used to monitor pitting corrosion.

Electrolyte: A substance through which charge is carried by the movement of ions.

External Corrosion Direct Assessment (ECDA): A four-step process that combines pre-assessment, indirect examination, direct examination, and post-assessment to evaluate the impact of corrosion occurring on the outside wall of a pipe upon the integrity of a pipeline.

Fluid: A substance that does not permanently resist distortion such as liquids and gases.

Flow Pattern: The distribution of the gas phase and the liquid phase as they flow through the pipeline and are dependant on both superficial gas and liquid velocities.

Fusion Bonded Epoxy (FBE) coating: this is an epoxy polymer that is electrostatically distributed evenly on a clean grit blasted pipe exterior and fused into a tough corrosion resistant coating using an induction coil to heat the steel pipe surface

Gathering System: Pipeline and related facilities to collect and move produced gas progressively starting from individual wells to a trunk, common or main line. Produced gas may not meet gas quality specifications typical of gas transmission systems.

Hydrostatic Testing: Testing of sections of a pipeline by filling the pipeline with water and pressurizing it until the nominal hoop stresses in the pipe reach a specified value.

Inclination Angle: An angle resulting from a change in elevation between two points on a pipeline, in degrees.

Indication: Any measured deviation from the norm.

Indirect Examination: Use of tools, procedures or models to examine a pipeline. WG-ICDA consists of calculating and comparing flow modeling results with (or without) an inclination profile and using Muhlbauer's method to prioritize the likelihood of integrity breaches.

In-Line Inspection (ILI): The inspection of a pipeline from the interior of the pipe using an ILI tool. The tools used to conduct ILI are known as pigs, smart pigs, or intelligent pigs.

Internal Corrosion Direct Assessment (ICDA): An integrity methodology that uses the direct assessment principles to address the threat of internal corrosion, one is applicable to dry gas and a second is used for normally wet gas systems.

Linear Polarization Resistance (LPR) Probe: Linear polarization resistance probes function by applying a small potential difference between two probe elements and measuring the resultant current. Through a series of measurements, the corrosion current and corrosion rates are determined. Note that unlike ER probes, each reading is independent of all previous measurements. Thus, process events, which affect corrosion, may not be detected by LPR probes unless the measurements are nearly continuous. LPR probes are also more susceptible to fouling.

Liquid: A substance that tends to maintain a fixed volume but not a fixed shape.

Liquid Holdup: Accumulation of liquid within a pipeline segment (i.e., input liquid volume is greater than output liquid volume).

Low Point: A location having higher elevations immediately adjacent upstream and downstream; any liquid is expected to preferentially collect at such locations during stagnant flow conditions. (Corrosion extent would tend to be greatest in those locations.)

Microbiologically Influenced Corrosion (MIC) – the presence of water and food sources allow the establishment and growth of biological films inside the pipe and these bacteria colonies encourage surface and electrolyte differentials which generally result in accelerated corrosion.

Mist Flow: A condition under which the liquid film thins considerably and a mist is carried down the pipeline with the gas.

Mitigation: Activities taken to reduce the internal corrosion severity inside a pipeline. For this standard, the objectives are to 1) determine the effectiveness of mitigation measures on the internal corrosion threat to establish priority in selecting candidates for the ICDA process, 2) correlate the mitigation technique data from a direct examination (inspection, cut-out, etc.) to history of operations and mitigations, and 3) determine, in the post-assessment step, the most effective mitigation measures to be taken after a direct examination.

Natural Gas: Primarily methane as produced from natural sources.

Pigging: *See In-Line Inspection or Cleaning Pig*

Potential Liquid Holdup Location: Pipeline locations and features, such as sags, drips, inclines, valves, manifolds, dead-legs, and traps, where liquids can accumulate.

Region: A continuous length of pipe determined by input, withdrawal, or processing. See Figure 3.

Segment: A portion of a pipeline that is (to be) assessed using WG-ICDA. Like ECDA & DG ICDA a segment may consist of one or more WG-ICDA regions. See Figure 3.

Slug Flow: A multiphase-flow regime in which liquids move along a pipeline in the form of intermittent volumes that fill the entire pipe cross-section.

Stratified Flow: A multiphase-flow regime in which fluids are separated into layers, with lighter fluids flowing above heavier (i.e., higher density) fluids.

Subtotal Corrosivity of a Sub-zone: A numerical value for corrosivity calculated from a summation/multiplication formula that includes the effects of mitigation, upsets and other operational factors, and excludes the effect of flow.

Sub-zone: A discontinuous piece of pipe (including weld joints) in a zone having similar corrosion conditions including potential damage, corrosion rate, types of corrosion, presences of solid, bacteria, inhibitor, hydrates, etc. See Figure 3.

Superficial Gas Velocity (V_{SG}): The volumetric flow rate of gas (at system temperature and pressure) divided by the cross-sectional area of the pipe.

Superficial Liquid Velocity (V_{SL}): The volumetric flow rate of liquid (water or water plus hydrocarbons) at system temperature and pressure divided by the cross-sectional area of the pipe. The ratio of V_{SL}/V_{SG} is the total liquid content of gas.

Mixture Velocity: The sum of both superficial gas and liquid velocities ($V_{SG} + V_{SL}$)

Overall Corrosivity of a Sub-zone: A numerical value for corrosivity calculated from a summation/multiplication formula that includes the effects of mitigation, upsets and other operational factors, as well as the effects of flow and corrosion duration interval of the sub-zone. It can be used to prioritize all sub-zones within all regions of a pipeline segment of interest for DA.

Tariff Quality Gas: Natural gas transported by a pipeline that meets certain compositional requirements, generally as related to the sale of natural gas. Tariff requirements differ among companies, but usually include specifications for water vapor (H_2O), hydrogen sulfide (H_2S), total sulfur (S), carbon dioxide (CO_2), heating value, and temperature.

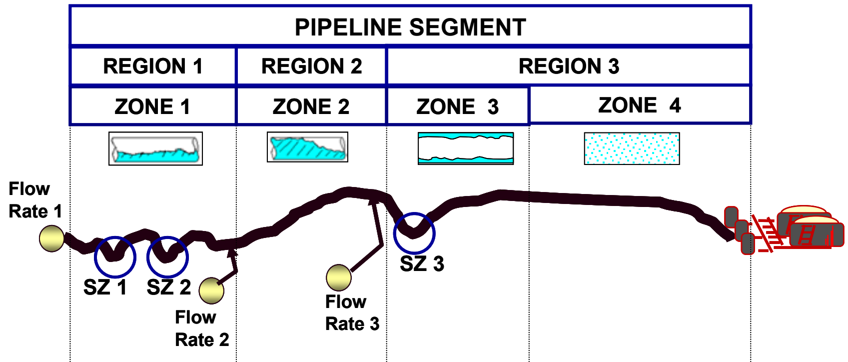
Total Corrosivity of a Sub-zone: A numerical value for corrosivity calculated from a summation/multiplication formula that includes the effects of mitigation, upsets and other operational factors, as well as the effect of flow. The effect of corrosion duration interval of the sub-zone is not included.

Upset: A situation where the pipeline operation differs from normal or steady state, and occurs within a relatively short time. This change may be caused by design or accidents. Upsets can result in change of flow, change of fluid chemistry, and change of pipeline surface condition, and potentially influence the pipeline corrosion. Upsets occur mainly during start up (commissioning), temporary shutdowns, restart or when a plant turns around. In contrast to normal operations, these processes result in a more dramatic change of the operation.

Wet gas: In the broad context, wet gas is defined as gas containing condensable hydrocarbons or water above their dew point concentrations (i.e., free liquids exist). For the purposes of this document, wet gas may be defined as any gas that does not meet the dry gas requirements.

Wet Gas Internal Corrosion Direct Assessment (WG-ICDA): A process as defined in this standard practice applicable to wet gas systems.

Zone: A continuous length of pipe (including weld joints) having the same flow pattern. See Figure 3.



PIPELINE SEGMENT = PIPELINE TO BE STUDIED

REGION = CHANGES IN VOLUMETRIC FLOW RATES, INPUTS OR PROCESS

ZONES = CHANGES OF FLOW PATTERNS

ZONE 1 = STRATIFIED FLOW

ZONE 2 = SLUG FLOW

ZONE 3 = ANNULAR FLOW

ZONE 4 = MIST FLOW

SUB-ZONE (SZ) = ZONES OF LIKE CONDITIONS, I.E., CORROSION, BACTERIA, LIQUID TRAPS

SZ 1,2,3 = SUB-ZONE 1,2,3 = ZONE OF LIQUID ACCUMULATION, BACTERIA ACTIVITY AND HIGH CORROSION RATES

Figure 3. Definition of Segment, Region, Zone and Sub-Zone.

Section 3: Pre-Assessment

3.1 Introduction

3.1.1 The objectives of the pre-assessment step are:

1) Collect as much information as possible related to pipeline design, operations (including historical), terrain and fluids.
2) Determine whether WG-ICDA is feasible for the pipeline being evaluated, or whether the system can be defined as a wet system but still contains small liquid volume fractions (typically less than 10% liquid/gas volumetric flow rate ratio). The liquid volumes included in this determination should include both water and hydrocarbon liquids.
3) Identify:
    - WG-ICDA regions by input, withdrawal, or processing,
    - Zones by flow-regimes, and
    - Sub-zones based on overall corrosivity including the effect of gas and liquid chemistry, flow, mitigation, upsets and other operational parameters.

3.1.2 The pre-assessment step requires data collection, integration, and analyses. The pre-assessment step must be performed in a comprehensive and thorough fashion.

3.1.3 The pre-assessment step includes the following activities:

3.1.3.1 Data collection (see Table 1);

3.1.3.2 Assessment of WG-ICDA feasibility; and

3.1.3.3 Identification of WG-ICDA regions.

3.2 Data Collection

3.2.1 The pipeline operator shall collect historical (i.e., over the life of the pipe) and current data, along with physical information for each segment to be evaluated. The data is grouped into five categories: 1) flow effects, 2) corrosivity, 3) mitigation, 4) upset, and 5) other operational factors.

3.2.2. Flow Effects: The effects of flow on corrosion must be known. A pipeline with more than one flow regime over a segment can have a corrosion distribution correlating with the flow regime. Each different flow regime is considered as a zone. Within a zone, the discontinuous pipeline pieces with different corrosion conditions due to differences in corrosion mechanisms are considered as sub zones. It can be expected that some uncertainty with respect to prediction of flow regime will be produced at areas where the transition is made from one type of flow regime to another.

3.2.2.1 Mist Flow: This is a condition under which the liquid film thins considerably and a mist is carried down the pipeline with the gas.

3.2.2.2 Stratified Flow: This is an area where the fluids separate into layers with lighter fluids flowing above heavier fluids.

3.2.2.3 Slug Flow: This includes all intermitted flows that episodically wet the entire pipe circumference.

3.2.2.4 Annular Flow: This is a condition whereby the liquid wets the entire pipe circumference and mist can be carried down the center of the pipe with the gas.

3.2.3 Corrosivity: This is based on gas quality, water chemistry, pressure, temperature and occasionally flow velocity.

3.2.4 Corrosion Mitigation

Corrosion mitigation includes activities undertaken to reduce the internal corrosion severity inside a pipeline. These activities need to be identified in this step because they will influence the determination of the likelihood for internal corrosive potential. The objectives of mitigation are to: 1) determine the effectiveness of mitigation measures on the internal corrosion threat to establish priority in selecting candidates for the ICDA process, 2) correlate the actual integrity data from a direct examination (inspection, cut-out, etc) to the history of operations and mitigations, and 3) determine the most effective mitigation measures to be taken after a direct examination. Most mitigation measures may be categorized into the five groups listed below:

a. Materials selection:
- Corrosion–resistant alloy: solid, thermal spraying or cladding
- Non-metallic: solid, coating or lining
- Others as determined by the operator

b. Dehydration, as being addressed under the Dry Gas ICDA standard (NACE RP0206-2006)

c. Chemical measures:
- Injection of a corrosion inhibitor
  The effectiveness of the corrosion inhibitor can vary over distance and is different for batch or continuous injection methods.
- Injection of a pH modifier (glycol for sub-sea pipeline)
- Coating with a batch chemical
- Injection of a biocide, wax/paraffin inhibitors
  The effects of biocides over distance are difficult to determine. The concentration and effectiveness of a biocide will vary depending upon their delivery method. Also, a pipeline with microbiologically influenced corrosion is expected to have large uncertainty with respect to predicted severity over distance.
- Others as determined by the operator

d. Mechanical/Physical measures:
- Maintenance pigging to remove water, wax/paraffin, solids, sludge
- Physical solvents to dissolve elemental sulfur
- Injection of hydrocarbon liquids to establish an oil film barrier

e. Others: such as internal cathodic protection and as determined by the operator

3.2.5 Upsets

An upset is a situation where the pipeline operation differs from normal or steady state and occurs within a relatively short time. This change may be caused by design or accidents. Upsets can result in change of flow, fluid chemistry, and pipeline surface condition, and potentially influence the pipeline corrosion. Upsets occur mainly during start up (commissioning), temporary shutdowns, restart or plant turn around. In contrast to normal operations, these processes result in a more dramatic change of the operation.

a. Change of fluid flow
At start up, the operation is not stable until after some time. During temporary shut down and plant turn around, the liquids stagnate at low spots. Upon re-start, either the gas flow cannot move all the settled liquids or it could result in slug flow when it empties the liquids. Temporary production surge or decline can also affect the fluid flow.

b. Change of fluid chemistry
During start up, the initial well bore self-cleaning might result in higher salinity, higher contents of silts and solids in the produced effluents. The inhibitors might be adsorbed by

the very large overall surface of the fine silts and solids produced, leaving less inhibitors available to protect the pipe surface. Also, it is possible that the high salinity exceeds the operating envelope of the inhibitors.

During temporary shut downs or plant turn around, the settling of solids, including sulfur, may lead to under-deposit corrosion. If the pipeline is opened, admission of air/moisture increases the likelihood of corrosion. The change of flow resulting from upsets also varies the corrosion condition.

During well work over, the introduction of low pH fluids and/or fluids with higher chlorides levels (if HCl is used) also increases the severity of corrosion.

The introduction of a foreign substance into the pipeline by design or by accident such as: (1) methanol/ethanol/glycol injection for hydrate control, (2) oxygen ingress due to vapor phase recovery operations and negative pressure seals for compressors, (3) dehydrator upsets (for wet pipelines with tie-ins which might have a dehydrating unit), (4) microbial activity (sulfate reducing bacteria or acid-producing bacteria) all increase the likelihood of corrosion.

c. Change of Pipeline Internal Surface Condition
During start up, the original surface of the pipeline covered possibly by mill scale (mainly oxides or hydrated oxides) may be converted to $FeCO_3$ and/or FeS due to corrosion caused by the acid gas CO_2 and/or H_2S. The passivity of the mill scale may thus be lost.

If the pipeline is opened for inspection/repair, or by vacuum, during temporary shut downs or plant turn around, moist air might be introduced and existing scale may be converted to hydroxides.

The temporary production surge or shut down also affects flow and the surface condition.

During moth balling/suspension, the pipeline might be blanketed with field fuels containing noticeably different acid gas compositions. Scales previously established on the pipe wall might be converted and might not offer the same corrosion resistance when the pipeline is re-commissioned.

During well work over, low pH fluids and/or higher chlorides levels (if HCl is used) can weaken/destabilize the previously protective scales.

3.2.6 Other effects: The likelihood of finding corrosion damage at a particular location along a pipeline segment is influenced by the following factors:

3.2.6.1 Liquid hydrocarbons: Liquid hydrocarbons can reduce corrosion by entraining water and not allowing it to directly contact the pipe wall and by sometimes acting as a corrosion inhibitor. However, it is possible for the water to drop out of the hydrocarbon layer over distance.

3.2.6.2 Bacteria: The effects of bacteria over distance are difficult to determine.

3.2.6.3 Solids: Solids include both organic and inorganic materials that are carried into a pipeline segment, precipitate from the liquids, and/or grow on the pipe wall. Depending upon the type of solids present, the solids may either accelerate or retard the corrosion rate.

3.2.6.4 Injected products: The influence of other products, such as glycol and methanol, can reduce corrosion rate. Their distribution can affect the location at which corrosion is likely to occur. In addition, degradation and reformation of treating chemicals could increase the likelihood of corrosion.

3.2.7 At a minimum, the pipeline operator shall collect essential data from the following categories, also depicted in Table 1. In addition, a pipeline operator may determine that items not included in Table 1 are necessary.

3.2.7.1 Defined length;
3.2.7.2 Diameter and wall thickness;
3.2.7.3 Pipeline characteristics;
3.2.7.4 Operating history;
3.2.7.5 Repair/maintenance data;
3.2.7.6 Corrosion inspection information;
3.2.7.7 Corrosion monitoring
The pipeline operator shall collect all historical and current data related to corrosion monitoring and inspection of the pipelines for evidence of internal corrosion. Two types of corrosion monitoring devices categorized as being intrusive and non-intrusive are described in Appendix C.
3.2.7.8 Other internal corrosion data;
3.2.7.9 Leaks/failures;
3.2.7.10 Cleaning pig history;
3.2.7.11 Hydrotest information;
3.2.7.12 Inputs/outputs;
3.2.7.13 Flow rate;
3.2.7.14 Water analysis and volume;
3.2.7.15 Elevation profile;
3.2.7.16 Gas quality;
3.2.7.17 Pressure;
3.2.7.18 Temperature;
3.2.7.19 Liquid chemistry;
3.2.7.20 Corrosion inhibitor;
3.2.7.21 Type of dehydration;
3.2.7.22 Internal coatings;
3.2.7.23 Anti-hydrate injection amounts; and
3.2.7.24 Upsets

3.2.8 The data collected in the pre-assessment step often include the same data typically considered in an overall pipeline (threat) assessment. Depending on the pipeline operator's integrity management plan and its implementation, the operator may conduct the pre-assessment step in conjunction with an External Corrosion Direct Assessment (ECDA) and/or other assessment effort.

3.2.9 When data for a particular category are not available, conservative assumptions shall be used based on the operator's experience and information about similar systems. The basis for these assumptions shall be documented.

3.2.10 In the event that the pipeline operator determines that sufficient data are not available or cannot be collected for some WG-ICDA regions comprising a segment to support the pre-assessment step, WG-ICDA shall not be used for those WG-ICDA regions until the appropriate data is obtained.

Table 1
Minimum Data for Use of WG-ICDA Methodology

CATEGORY	DATA TO COLLECT
Defined length	Length between inputs/outputs and processing.
Diameter and wall thickness	Nominal pipe diameter and wall thickness.
Pipeline characterization	Materials according to API – API 5L Grade, microstructure, weld type and material, chemical composition, geometries: elbows, T´s, expansions, reductions, valves, etc. Pipeline material, microstructure, weld material and other contributors to internal corrosion data such as locations of sludge deposits, hydrates, emulsions etc. Including date of construction.
Operating history	Including periods of inactivity or abnormal activity; change in gas flow direction, type of service, removed taps, year of installation, etc. Has the line ever been used previously for crude oil or other liquid products? In addition, it is also helpful to gather data concerning the length of time that the lines in storage fields are being used for injection (normally dry), withdrawal (normally wet) or inactive.
Repair/maintenance data	Presence of solids, anomalies; pipe section repair and replacement; prior inspections; NDE data. Any cleaning pig locations, frequencies, and dates. Analytical data of all removed sludge, liquids when cleaning pigs were employed or from liquid separators, hydrators, etc. and the analysis performed to determine chemical properties and corrosivity, including the presence of bacteria, of the removed products.
Corrosion inspection information	This information may include data from previous in-line tool inspection runs, coupons, ER probes and LPR probes. In addition, any time that a pipeline is cut open, information on internal condition of the pipe should be evaluated.
Corrosion monitoring	Corrosion monitoring data including type of monitoring [e.g., coupons, electric resistance (ER)/linear polarization resistance (LPR) probes], dates and relationship of monitoring to pipe location, corrosion rate recorded/calculated, and accuracy of data (e.g. NACE A3T199: "Techniques for Monitoring Corrosion and Related Parameters in Field Applications"). Any available non-destructive inspection results.
Other internal corrosion data	As defined by the pipeline operator such as locations of sludge and hydrates, etc.
Leaks/failures	Locations and nature of leaks/ failures.
Cleaning pig history	Frequency and effectiveness of cleaning pigs
Hydrotest information	Past presence of water, hydrotest water quality data.
Inputs/outputs	Must identify all locations of current and historic inputs and outputs to the pipeline.

CATEGORY	DATA TO COLLECT
Flow rate	Flow rates—normal, maximum and minimum flow rates at minimum and maximum operating pressures for all inlets and outlets. Significant periods of low/no flow.
Water analysis and volumes	Volume of water transported by the system. Including source of water (condensed water versus free water from underground reservoir). Drips and separators are locations where free water is collected. Water vapor dew point
Elevation profile	Topographical data (e.g., USGS [10] data), including consideration of pipeline depth of cover. Take care in instrument selection that sufficient accuracy and precision may be achieved.
Gas quality	Gas and liquid analyses, and any bacteria testing results for the pipeline and on shipper and delivery laterals. Gas chromatography at least to up to $C1_2$, H_2S, CO_2, specific gravity, gas density. Relationship of gas analyses to pipe location. The presence of any solids or dusts being carried in the system may have an effect on the corrosivity of the system.
Pressure	Typical normal, minimum and maximum operating pressures. Design pressure should also be collected.
Temperature	Temperature profile along pipeline length. Useful parameters include compressor discharge temperature, soil temperature and any temperature along the pipeline where measured.
Liquid chemistry	The chemistry of the liquid phase has a direct bearing on the corrosivity of the system. This includes the presence of scale in free water. This also includes the presence and quantity of hydrocarbons.
Corrosion inhibitor	Information about injection, chemical type, and dose. This shall also include when inhibition was started, how long it was used, and how effective it was. Batch and continuous, solubility and dispersibility in hydrocarbon and aqueous phases. Biocide treatments.
Type of dehydration	Is dehydration carried out using glycols (yes/no)?
Internal coatings	Existence and location(s) of internal coatings.
Anti-hydrate treatments	Injection volumes for liquids being injected into the system to prevent the formation of hydrates. Methanol is often used.
Upsets	Frequency, nature of upset (intermittent or chronic), volume if known, and nature of liquid.

3.3 WG-ICDA Feasibility Assessment

The pipeline operator shall examine the data collected in Paragraph 3.2 to determine whether conditions that would preclude this WG-ICDA application or for which indirect examination tools cannot be used.

The following conditions are required to apply this WG-ICDA standard:

3.3.1 Sufficient data is available regarding the overall composition and especially the water content of the gas to determine which method may be used to locate points of the most severe corrosion. Also, sufficient data should be available to determine factors affecting the corrosion rate(s).

3.3.2 The pipeline may have been previously converted from an alternate service pipeline (e.g., crude oil or products). It must be demonstrated either that internal corrosion did not occur in the previous service or that previous damage has been quantified and separately assessed.

3.3.3 The pipeline may have an internal coating that provides corrosion protection. For pipelines with discontinuous protective coatings, indirect examinations must be performed at non-protected locations. (Crevice corrosion, in particular, and other forms of corrosion, such as pitting or MIC, may also need to be considered as a liquid layer under disbonded coating or sludge could result in the above problem(s).)

3.3.4 Pigging distributes pooled liquids, which directly affects the distribution of internal corrosion in a way that is not restrained by the inclination angle consideration of DG-ICDA. Thus, WG-ICDA for pipelines that have been routinely pigged will have to consider the ILI transport of electrolytes and injectants. The operator must provide technical justification if ILI activities change the high probability corrosion locations

3.3.5 Pipelines that contain accumulations of solids, sludge, biofilm/biomass, or scale may be assessed using this WG-ICDA standard. The influence of those materials should be carefully evaluated. Based on information collected in Sec. 3.2 (See Table 1), operators must determine whether accumulations of solids are significant enough to influence the validity of the WG-ICDA results through any of the mechanisms described below. The presence of solids, sludge, and scale could affect the validity of this WG-ICDA process and need to be considered for:

- Increasing corrosion through retaining water under a solid layer,
- Increasing corrosion by attracting water through hygroscopic properties and/or deliquescence,
- Increasing corrosion through the formation of a concentration cell (i.e., under-deposit corrosion);
- Decreasing corrosion through the formation of a protective layer, and
- Changing corrosion rates due to the influence of bacteria.

3.3.6 Material Properties

WG-ICDA assumes uniform material properties along a pipeline segment. Consideration for differences such as repair pup insertions, weld type and geometry and material defects must be made. Special consideration should be given for possible selective-seam corrosion on some older known susceptible electric resistance welded pipe.

3.4 Identification of WG-ICDA Regions

Pipeline operators shall define WG-ICDA regions from the data collected in the pre-assessment step. See Figure 3.

3.4.1 A WG-ICDA region is a portion of pipeline with a defined length, or any length of pipe prior to a new input that introduces the possibility of corrosion whose extent and severity exceed the acceptance level before the next assessment.

3.4.2 In defining WG-ICDA regions, the operator shall consider process changes such as temperature and pressure. Significant changes within the segment length should be considered as separate WG-ICDA regions.

3.4.3 Input changes also include new directions of gas flow. In the case of bidirectional flow history, WG-ICDA regions shall be identified for each flow direction, and each flow direction shall be treated separately.

3.5 Identification of WG-ICDA Zones

Zones are those portions of the pipeline defined within a region as having the same flow pattern. Zones can be discreet segments of a pipeline. See Figure 3. Up to five types of zones can be defined in a region as shown in Table A.2 in Appendix A.

3.6 Identification of WG-ICDA Sub-Zones

WG-ICDA sub-zones are pipeline segments within a zone that have similar internal corrosion conditions based on history and/or the possibilities of presence or absence of corrosivity, mitigation, upsets and other operational factors as shown in Table A.1 in Appendix A. Table A.1 also shows that up to nine types of sub-zones are possible. The other factors include, but are not limited to, possible bacteria proliferation, solid deposition, hydrate formation, weld joints, liquid accumulation (hold-up), etc.

Section 4: Indirect Examination

4.1 Introduction

The objective of the WG-ICDA indirect examination step in a region is to use flow prediction to determine the zones, then apply the five factors to determine sub-zones. Finally Muhlbauer's methodology[3] and corrosion prediction tools are used to prioritize those sub-zones most likely to have suffered severe internal corrosion within each WG-ICDA zone. An example is given in Appendix A that displays how the overall corrosivities of all sub-zones within a pipeline segment are numerically determined and ranked. The WG-ICDA indirect examination step relies on the ability to identify locations where the mode of flow and the related corrosion mechanisms are most likely to cause corrosion (high overall corrosivity) and pinpoint sub-zones where the integrity of the pipeline may be compromised (high severity of corrosion). The sub-zones are prioritized from high corrosion severity to low or zero severity, and the resulting priority list determines where and when to dig. Dry gas ICDA[1] is a subset of WG-ICDA where unplanned introductions of water have not traveled down the entire region but have been trapped at a distance from their introduction.

If there has been bidirectional flow through the pipeline, the opposite direction shall be considered as separate WG-ICDA region(s), and each direction shall be treated separately.

The WG-ICDA indirect examination step shall include each of the following activities for each WG-ICDA region:

4.1.1 Depending on the water composition (based on the superficial water velocity), determine whether this section of pipeline carries dry gas and if so, a critical angle approach will be valid and should be calculated to determine locations of water holdup. For dry gas, Reference 1 describes a more detailed procedure. If this pipeline section carries wet gas, the critical angle concept is not valid and flow modeling needs to be performed to determine flow regimes (e.g., stratified, slug, etc.). Appendix D shows graphical examples of when the critical angle approach may not be valid. A detailed flow modeling procedure is given in Section 4.2.

4.1.2 Produce a profile of corrosion severity or remaining pipe wall thickness along the pipe segment based on overall corrosivity of sub-zones as calculated in the example given in Appendix A. The overall corrosivity varies with physical trapping sites, pressure, temperature, flow velocities and flow patterns. Periods of abnormal flow must be considered, especially if the section was inactive or idle for a period of time.

4.1.3 Modes or regimes of flow are predicted in this step with flow models and the predicted overall corrosivity of sub-zones is to be considered in assessing possible pipe wall damage.

4.1.4 Identify all of the sub-zones on a map. These represent all the locations where internal corrosion may have been present for significant intervals. Identify potential damage sites on the pipeline such as traps, inclination profile and the other various modifying factors that were used in the steps of Section 4 to influence the corrosivity. Estimate the duration of this corrosivity in each sub-zone. Model the damage as a product of corrosivity times duration, then order all the sub-zone locations by expected damage severity of internal corrosion. A comparison should be made between known pre-assessment damage by location and the predicted damage. The operator will be required to set three thresholds for expected corrosion damage: high, medium and low (similar to immediate, scheduled and monitored used in ECDA). These three thresholds determine the excavation prioritization of the sub-zones for Direction Examination. Operational factors may influence the actual chronological order, but those predicted to have the highest threat should be addressed first.

4.2 Flow Modeling

The operator shall predict critical parameters for flow patterns by using flow modeling for each identified WG-ICDA region. Any appropriate method to predict flow characteristics along the pipeline length is acceptable. For the prediction, only a portion of the pipeline may be modeled with the rest to be extrapolated. The prediction requires information about the topography of the pipeline location because the fluid flow inside a pipeline can be strongly influenced by gravity, in addition to the gas and liquid properties, the inner surface roughness of the pipeline and others. The typical flow profile is a 3-D co-ordinate survey (XYZ) of the pipeline. However, for most, if not all, practical purposes, the flow modeling software will utilize only altitude versus distance (XZ) from the 3-D profile due to symmetry in the Y direction.

For the purpose of ranking the corrosion severity for prioritization, it is not always practical to perform flow modeling on all pipelines using actual full-length altitude versus distance profiles. Due to the variable actual topography of the pipeline, the evaluators might consider using sub-groups of "generic" topographical profiles. The following seven classes of terrains or profiles are suggested, although depending on the user, values beyond the above classifications may be considered. For risers, the users may consider adding two more classes (uphill and downhill).

- Flat terrain where the slopes are between -1 to 1%
- Slightly uphill: slopes are between 1 and 5%
- Moderately uphill: slopes between 5 and 15%
- Extreme uphill: slopes greater than 15%
- Slightly downhill: slopes between -1 and -5%
- Moderately downhill: slopes between -5 and -15%
- Extreme downhill: slopes steeper than -15%

For an effective prediction of flow regime, the above generic topographical profiles are used and the following procedures are followed. First, the generic profiles for the pipeline of interest are prioritized. In this step, flow modeling is conducted on all generic profiles utilizing the nominal pipeline diameter, operating conditions (pressure, temperature, etc.) and production flow rates (gas, water, liquids, etc.).

In the second step, for the highest rated overall corrosivity terrains, the actual topographical profile instead of a generic profile will be used in flow modeling to more accurately determine flow regimes.

The above simplified flow modeling approach to prioritizing overall corrosivity terrains based on generic profiles should be directly applicable to all systems with stratified flow, although the modeling to include the top of the line corrosion in consideration of condensation may not be easily accomplished. For prediction of flow regimes using generic topographical profiles, the following bounds need to be taken into account:

- Nominal pipe diameter between 0.1 and 1.2 m or between 4 and 48 inches unless flow modeling has been performed outside this range, and

- Pressures less than 7.6 MPa (1,100 psi) unless flow modeling has been performed at higher pressures or other technical justification has been provided.

4.3 Corrosion Severity Influencing Factors

To prioritize locations for excavation, the overall corrosivities of all sub-zones must be evaluated numerically after considering each of the factors, then ranked as done in the example given in Appendix A. Since corrosivity is influenced by many factors, for reliable determination of overall corrosivity of a sub-zone, first all the corrosivity-influencing factors must be known or estimated so their values can be numerically assigned based on the significance of their influences either by calculation using well-established software tools if available or by expert's opinion after the methodology of Muhlbauer. The corrosion mechanisms need to be understood in order to determine corrosivity for a reliable estimate of influencing factors.. The following provides a rather qualitative discussion of the many factors and how they influence corrosivity.

Understanding corrosion mechanisms (a combination of fluid flow and chemistry) is key to assessing the significance of the events. Some events require an induction time to create conditions for corrosion to initiate. Understanding the introduction time can be important. In the case of a pit of certain depth, if it is initiated during an upset, for instance, the pit may still continue to grow even though non-corrosive conditions may be restored later on. This is because the local pit-growing chemistry is only modestly changed by the new condition. For propagation, the corrosion is affected by many factors that need to be understood. These factors are important to predict corrosion rate and include pipeline history addressed in the pre-assessment, gas quality, presence of solids, inhibitor, bacteria and hydrates. The factors also include fluid flow, abnormal operations or upsets and mitigation measures taken to reduce corrosion. The effects of these factors on corrosion are analyzed separately below:

4.3.1 Corrosion mechanisms due to gas quality

4.3.1.1 Background

Gas quality specifications are set for commercial and contractual considerations, designed to prevent corrosion and to prevent blockages from freezing, hydrate formation and by the heating value of the natural gas. Gas quality requirements differ between companies and sometimes business units, and no industry standard exists to address this issue. A review of tariff gas composition specifications pertinent to corrosive gas constituents[11] showed that CO_2 can vary from 0.8 to 4 percent, H_2S from 4 to 16 ppm and O_2 from a few ppm levels to 1 mole percent. The actual concentrations of some of these constituents are seldom measured. Of the one hundred and six node points of gas transactions recently surveyed (GRI 8715 & Office of Pipeline Safety (OPS) Contract No. DTRS5603T0001) only ten nodes reported measured O_2 concentration, which ranged from 20 to 5800 ppm. These corrosive species directly influence the internal pipeline corrosion rate.

In the case of gathering lines, the CO_2 and H_2S levels may vary widely beyond the above stated limits.

4.3.1.2 Effect of dissolved CO_2:

It has been found that steel corrosion rate in H_2CO_3 is greater than in HCl for the same solution pH, attributed to the fact that H_2CO_3 itself can be reduced at the steel surface to form hydrogen. The presence of CO_2 definitely increases the pipeline corrosion rate. However, research shows that CO_2 hydration can be a slow homogeneous reaction and limit the corrosion process. Steel corrosion due to dissolved CO_2 alone is a complex phenomenon and has been studied extensively[12-26]. In the operating temperature range, $FeCO_3$ may precipitate and vary the corrosion rate.

4.3.1.3 Effect of dissolved H_2S:

Depending on gas quality, H_2S may be beneficial or detrimental to the pipeline corrosion. Too little or too much H_2S can increase the corrosion rate, while in some mid-range concentrations, the formation of FeS is passive and can decrease the corrosion rate. When there is too much H_2S, the passivity of FeS is saturated at the steel surface. Further, as the H_2S content increases, the solution pH decreases and the corrosion rate increases. Refer to NACE MR0175/ISO15156[27] for other H_2S corrosion mechanisms.

In solutions with dissolved CO_2 and H_2S, the solution is acidic. Too little H_2S content may not result in formation of FeS, even though FeS has much lower solubility than $FeCO_3$. Although there exists a molar ratio of CO_2 to H_2S in the gas phase at which the precipitate exchanges between FeS and $FeCO_3$ and this ratio was determined theoretically to be roughly 1400[28], it has been found experimentally that this rate is roughly 500[26].

- If the ratio of CO_2/H_2S is greater than 500, the corrosion products tend to be iron carbonate and the corrosion mechanism is very much like CO_2 corrosion alone. H_2S would have little impact on the corrosion severity.
- If the ratio is less than 20, the corrosion products are iron sulfide which, if undamaged, would reduce corrosion to a very low level. However, in the presence of high Cl^- (greater than 10,000 ppm), elemental sulfur, oxygen, sludge, or if the flow regime is either slug or stagnant, or if the concentrations of some mitigating corrosion inhibitors are not

sufficient, iron sulfide scale can break down locally, resulting in very severe pitting corrosion at a rate often equivalent to the CO_2 corrosion rate.

- If the ratio of CO_2/H_2S is between 20 and 500, both iron carbonates and sulfides can co-exist. Research is still in progress for this mixed corrosion mechanism.

4.3.1.4 Effect of Dissolved O_2:

Dissolved O_2 can increase the steel corrosion rate. This corrosion is diffusion limiting. Although in the corrosion process O_2 reduction at the steel surface can generate hydroxide ions or increase the local pH and potentially decrease the hydrogen ion and water reduction rates, overall, the increase of steel corrosion dominates. This increase in corrosion rate caused by O_2 can be approximated by the O_2 diffusion limiting current density[18].

4.3.2 Corrosion mechanisms due to mitigation

Mitigation measures are developed to respond to corrosion mechanisms under different flow regimes and different operating conditions (temperature, pressure and gas composition). Understanding corrosion mechanisms under the influence of fluid flow and chemistry is important to assess the significance of corrosion and help to define effective measures to mitigate corrosion.

4.3.2.1 Mitigation by inhibitor:

Inhibitor is used in gas pipelines to prevent or mitigate corrosion. Inhibitor decreases corrosion rate by forming a protective barrier on a corroding metal surface. Depending on the chemical type, dose and how it is used (batch and continuous, oil soluble and water dispersible), its protective effectiveness and endurance varies. Other factors influencing effectiveness and endurance include flow conditions and the ratio of liquid hydrocarbon to water.

For batch application, the downstream pipe may be inhibited longer than upstream portions due to re-adsorption of inhibitor desorbed from upstream locations. The situation can become worse if the batch frequency is determined by downstream monitoring.

For continuous injection, the inhibition effectiveness can depend on distance. The effectiveness of inhibitors can be reduced over distance if the relative volumes of hydrocarbon to water increase or the degree of mixing (by emulsions or flow regime) decreases over distance.

Removal of liquids removes inhibitor. If there is a low liquid volume throughput but a high liquid volume holdup, and if there is frequent pigging, an inhibitor may not reach downstream sections of the pipe. The inhibitor can reach downstream locations only after the upstream holdup locations are full. For some pipelines this process can take months.

The effectiveness of inhibitor can also be affected by factors of flow pattern, presence of solids, or water content, among others. These factors may either mechanically or chemically damage or destroy the inhibition. The wet/dry conditions may render the inhibitor to be chemically ineffective.

4.3.2.2 Examples where mitigation measures could lose their effectiveness:

a. In the case of an existing pit initiated during upset and exceeds a minimum depth, the pit growth may continue even after non-corrosive conditions are restored. For such a pit, continuous injection of inhibitors may not be effective since the inhibitor may have difficulty reaching the bottom of the pits.

b. For corrosion under a stratified flow regime, continuous injection of inhibitor may not be capable of dispersing itself in the water phase.

Under stratified flow, the inhibitor may not be capable of being transported to the vapor phase to reduce the threat of top of the line corrosion.

c. If the inhibitor is injected for the reason that the flow regimes are dynamic enough to disperse in water phase, when intermittent production is frequent, the inhibitors may not sufficiently disperse in stagnant waters during the idle periods to be effective.

d. If the inhibitor is used because it passed laboratory testing and is proven to be effective in similar fields, when the line operates with frequent fluid surges containing higher Cl^- content or when the liquid water content has a significant increase while the inhibitor injection rate does not change, the inhibitor may not be effective.

e. If the mitigation measure is applied inconsistently or it is frequently interrupted, the mitigation measure may not be effective. For instance, if the inhibitor pump is down 20% of the time or the tank is empty 5% of the time, it may not be effective.

f. If mitigation measures are incompatible with fluids or activities that are not inherent in the operating conditions, they may not be effective. For instance, since the batch inhibitor is soluble in methanol, if the methanol was injected more frequently to prevent hydrate formation, the batch film may lose adherence to the pipeline.

g. If there is no performance tracking system in place to assess the effectiveness of mitigation measures or to correct deficiencies in implementation of the mitigation measures, past lessons on ineffective mitigation measures may not be learned.

4.3.3 Corrosion mechanisms due to change of operations/upsets

An upset, caused by design or accidents, can result in change of flow, fluid chemistry, and pipeline surface condition. Each of these conditions can potentially influence pipeline corrosion. Upsets occur mainly during start up (commissioning), temporary shutdowns, restart or plant turn around. In contrast to steady state or normal operations, these processes result in a more dramatic change of the operation.

4.3.3.1 Change of fluid flow:

Operation of the pipeline is not stable until some time after start up. During temporary shut down and plant turn around, the liquids stagnate at low spots. Upon re-start, either the gas flow cannot move all of the settled liquids or it could produce slug flow when it empties the liquids. Temporary production surge or decline can also affect the fluid flow.

4.3.3.2 Change of fluid chemistry:

During start up, the initial well bore self-cleaning might result in higher salinity, and/or higher contents of silts and solids in the produced effluents. The inhibitors might be adsorbed by the very large overall surface of the fine silts and solids produced, leaving less inhibitors available to protect the pipe surface. Also, it is possible that the high salinity exceeds the operating envelope of the inhibitors.

During temporary shut downs or plant turn around, the settling of solids, including sulfur, may lead to under-deposit corrosion. If the pipeline is opened, admission of air/moisture increases the likelihood of corrosion. The change of flow resulting from upsets also varies the corrosion condition.

During well work over, the introduction of low pH fluids and/or fluids with higher chlorides levels (if HCl is used) also increases the severity of corrosion.

The introduction of a foreign substance into the pipeline by design or by accident such as: (1) methanol/ethanol/glycol injection for hydrate control, (2) oxygen ingress due to vapor phase recovery operations and negative pressure seals for compressors, (3) dehydrator upsets (for wet pipelines with tie-ins which might have a dehydrating unit), (4) microbial activity (SRB or acid-producing bacteria) all increase the likelihood of corrosion.

During hydrotesting, if water was not properly treated, it may induce internal corrosion as well as bacteria growth. Corrosion may continue if the pipe is not totally dried before it enters into operation.

4.3.3.3 Change of pipeline internal surface condition

During startup, the original surface of the pipeline covered possibly by the mill scale (mainly oxides or hydrated oxides) may be converted to $FeCO_3$ and/or FeS due to corrosion caused by the acid gas CO_2 and/or H_2S. The passivity of the mill scale may thus be lost.

If the pipeline is opened for inspection/repair, or by vacuum, during temporary shut downs or plant turn around, moist air might be introduced and existing scales may be converted to hydroxides.

The temporary production surge or decline also affects flow and the surface condition.

During idle/suspension conditions, the pipeline might be blanketed with field fuel gas containing acid gas contents different from the previously produced effluents. Scales previously established on the pipe wall might be converted into a different type and might not offer the same corrosion resistance when the pipeline is re-commissioned.

During well work over, low pH fluids and/or higher chlorides levels (if HCl is used) can weaken/destabilize the previously protective scales.

Liquid hold up or traps at fittings or design locations such as low points, drips, etc. should be considered.

4.3.4 Corrosion mechanisms due to other factors

4.3.4.1 Effect by the presence of bacteria

The presence of bacteria can change the chemistry of the solution at the steel pipe surface and therefore change the corrosion rate. The effects of bacteria as a function of distance can be difficult to predict. A pipeline known to suffer from microbiologically influenced corrosion (MIC) is expected to have higher corrosion uncertainty. If MIC is considered to be an important mechanism, added excavations may be necessary.

4.3.4.2 Effect of liquid hydrocarbons

Liquid hydrocarbons can decrease the corrosion rate by entraining water. If water is dispersed in the hydrocarbon phase, the corrosion rate is expected to be lower than if it is directly in contact with the pipe wall.

If hydrocarbons condense along a pipeline segment resulting in an increase in its ratio to water, it is possible that corrosion is less likely at downstream locations. This is particularly true if liquid water dominates at upstream locations.

Some hydrocarbons may decrease corrosion rate by inhibition mechanisms similar to inhibitors. The efficiencies can depend on the water to hydrocarbon ratio.

If water is emulsified in a continuous hydrocarbon phase, and if this emulsion can break over distance, 'free' liquid water may form. If the flow regime is stratified, liquid water might drop to the pipe bottom to increase the likelihood of corrosion at downstream locations. This effect might be less if the flow regime is slugging or annular because the liquid phases are mixed.

4.3.4.3 Effect by the presence of solids

Pipelines may contain accumulations of solids, sludge, biofilm/biomass, or scale. They are carried into a pipeline segment, precipitate from the liquids, and/or grow on the pipe wall. Sources of solids include corrosion products (e.g., iron carbonates, iron sulfides), other inorganic scales (e.g., calcium carbonate, barium sulfate), organic scales (e.g., paraffins, asphaltenes), and carryover of solids, including silicates (e.g., formation sand), into the pipeline segment. Such solids can have several effects on corrosion. Scales primarily affect the transport of materials to (or from) the pipe wall or the surface solution chemistry and the kinetics of electrochemical reactions. They may also affect flow characteristics if a sufficiently large volume of solids exists to reduce the effective pipe diameter. Their presence in pipeline may increase the corrosion rate through retaining water by their hygroscopic properties and/or deliquescence, or through the formation of a concentration cell or crevice corrosion under deposits. They can decrease the rate of corrosion if they form an intact protective barrier layer. Their presence also increases the likelihood for bacteria growth.

4.3.5 Corrosion mechanisms due to gas flow parameters

The flow parameters can have a significant effect on the corrosion rate because they can change the transport of solution species and the pipe surface condition. The expected possible flow regimes are mist, annular, stratified, and slugging. A pipeline with similar flow parameters (flow regime, velocity) may have corrosion distribution determined only by non-flow related corrosivity factors (i.e., gas quality, inhibitors, etc.). A pipeline with more than one flow regime over distance can have a corrosion distribution affected by the flow regime. A first step to determine locations for wet gas ICDA (i.e., pre-assessment) is aimed at classifying the pipeline into regimes and the relative corrosion behavior of the different regimes is prioritized.

Considered as secondary, the flow effects on corrosion can differ within one regime. For example, an area identified as slug flow does not indicate the slug frequency or severity. Similarly, defining an area as stratified does not discriminate between wavy and smooth. Defining an area as annular flow does not consider film velocity or amount of mist. Condensing water in locations of high heat loss can be considered as an additional influence on corrosion initiation and growth when it occurs under a stratified flow regime. This effect on top of line corrosion is less important for pipe containing slug or annular flow.

This section determines how chemical treatment (if applied properly or improperly) might result in a non-uniform effectiveness along a pipeline length. For example, for an oil soluble batch treated inhibitor, is inhibitor effectiveness better upstream or downstream? This section is not about making good decisions; it is only about how the effectiveness differs at one location versus the other, given some historical data on chemical treatment (e.g., inhibition and biocides).

4.4 Prioritization of Sub-zones Based on Overall Corrosivity

For internal corrosion of gas pipelines, the corrosion rate depends on many factors including the pipeline history, gas quality (CO_2, H_2S, O_2, water contents), gas flow parameters, mitigation, upsets, the elevation profile of the pipeline temperature, pressure, presence of solids, hydrates, and others. Although under certain conditions the defect growth rate and size can be predicted to allow pipeline operators to determine the remaining wall thickness and the next reassessment interval, in the majority of circumstances, they are difficult to determine as these rate-influencing factors can be impossible to quantify accurately. In such cases, a qualitative and comprehensive, conservative approach is more desirable. Such an approach may be considered similar to a relative scoring/ranking methodology. To implement this approach, a group of experts will discuss the major controlling factors responsible for corrosion within a zone and apply a weighting to each factor. By combining all these weighted factors together through summation or multiplication, a total score is obtained for each sub-zone. If duration is combined with the total score by multiplication for each sub zone, a relative ranking of all sub-zones within a region can be obtained. By setting three thresholds, i.e., high, medium and small, the relative comparison allows for ranking of all sub-zones within a region for prioritization of digging. Refer to the example in Appendix A.

When conditions for sub-zones are known and corrosion rates can be predicted, the corrosion rate determination can play a significant role for prioritization of locations to dig. Operational conditions may necessitate a change in priority, but in general, those that are high are investigated first. Practices of corrosion rate estimation are described below.

Corrosion rate estimation can be verified by empirical alignment or extrapolation of the measured wall loss through repetitive measurement of the same location or engineering relationships to similar locations. These methods are not only expensive, but without correlating directly with changes of rate-determining variables such as pH, potential, temperature, degree of aeration, etc., can add unknown uncertainty to similar sub-zone correlations. When the operating conditions vary due to changes in gas quality, flow, temperature, pressure and/or inhibitors, corrosion mechanisms may become significantly altered. Such variations in operating conditions are considered as secondary effects, and are not included in the above empirical/extrapolation techniques.

A realistic default rate for internal pipeline corrosion does not yet exist and needs to be developed. Since simple empirical methods of estimating corrosion rate are not generally useful for extrapolation, models developed based on fundamental corrosion principles are desirable. Reliability of the corrosion rate prediction can be improved by including the pipeline corrosion potential variations with location and time. Because such variations are observed in the field, the corrosion potential estimated from the above empirical/extrapolation techniques can be conservative in one case and non-conservative in another.

There are a number of CO_2 corrosion models[12-25] in the literature which have primarily been developed for oil production systems. Access to these models is limited as most are embedded in proprietary software not readily accessible for general use and are not cost-effective for occasional use by operators. A model that is developed based on fundamental principles while easy to use and readily accessible is most desirable. Further research is still needed in this area.

4.5 Site Selection

Sites at which internal corrosion may be present shall be determined by integrating the flow-modeling results to determine zones. Five deterioration mechanisms or factors influencing corrosion potentials determine the sub-zones. The duration of corrosion potential in the sub-zone determines the magnitude of the internal corrosion threat. The process applied for site selection is outlined below.

4.5.1 Pick the segment.
4.5.2 Set the beginning and ends of any new region coincident with input/withdrawal/dehydration activities. Assume fully independent regions (i.e., no prioritization).
4.5.3 Determine flow regimes to define zones:
- Slugging
- Stratified
- No liquids
- Stagnant
- Unknown

4.5.4 Define sub-zones by estimating the overall corrosivity using criteria for susceptibility to corrosion based on history, corrosivity, upsets, mitigation and other. Pre-assessment data can be useful. Consider the duration of corrosion in each sub-zone.
4.5.5 Prioritize the sub-zones by expected severity of damage.
4.5.6 Dig at the highest priority sub-zone.

4.6 Dig priority of sub-zones

The priority for the excavations and detailed examinations was determined in the Section, 4.5. The threat of internal corrosion or estimated cumulative wall loss was determined by first considering the different flow regimes or zones. Different flow regimes represent different distributions of corrosion threat. Each flow regime is considered susceptible to corrosion. Similar corrosion mechanisms and influencing factors in each zone separate them into corresponding sub-zones that may be discontinuous. The sub-zones (i.e., similar flow, similar corrosion mechanisms, etc.) will be influenced by historical operating, mitigative and preventive activities. Upsets, both planned and unplanned, the introduction of inhibitor or biocide treatment solutions, or the use of spheres or pigs to clean the line, will help distribute electrolytes downstream. The excavation priority of the sub-zones should be set by the overall corrosivity of a sub-zone, with the most severe being investigated first.

Section 5: Detailed Examinations

In WG-ICDA, water is considered to be present throughout the line, and thus, internal corrosion can occur anywhere in the region. In WG-ICDA, the objective is to find locations with the highest potential wall loss.

1. In prioritization, the historical metal loss must be taken into account. A location with lower corrosion rate but occurring over long intervals can be more significant than locations with no historical corrosion, but the current corrosion rate is higher. Known, pre-existing defect sizes and their current corrosion rates are coupled to determine the level of the internal corrosion threat.
2. Upset conditions and mitigation measures shall be taken into account in the prioritization.
3. If the pipeline has experienced bidirectional flow, the effect(s) of changing flow direction on corrosion distribution at selected sites shall be considered.
4. If the pipeline has been subjected to bidirectional flow, detailed examination process must consider flows in both directions.

5.1 Introduction

5.1.1 The objectives of the WG-ICDA detailed examination are to:
i) determine if internal corrosion exists at locations selected in the previous step, and
ii) use the findings to assess the overall integrity of the WG-ICDA region.

5.1.2 The detailed examination step focuses examination efforts on identified and prioritized sites and features most likely to experience internal corrosion.

5.1.3 Excavation and subsequent inspection must be sufficient to identify and characterize the internal corrosion features in the WG-ICDA region.

5.1.4 Procedures for conducting nondestructive inspection techniques (NDT) and subsequent actions to be taken as a result of identifying anomalies found during the inspection are not included in the scope of this standard. The operator must follow the appropriate guidelines located in related NACE, ASME or other International standards for evaluating each found anomaly for and responding to the presence and extent of corrosion.

5.1.5 During the detailed examination step, threats other than internal corrosion may be found. While external corrosion, mechanical damage, SCC or other damage may be found, alternative methods must be considered for assessing their impact on system integrity.

5.1.6 Methods to assess the significance of confirmed corrosion can be found in ASME B31.8,[6] ASME B31.8S,[6] API 1160,[7] ANSI/API 579,[8] BS7910[9] NACE standards, international standards, and other documents.

5.1.7 The priority in which excavations and detailed examinations are made was determined in Section 4. The risk of cumulative wall loss was determined by first considering the different flow regimes or zones. Different flow regimes represent different distributions of the corrosion threat. Each flow regime is considered susceptible to corrosion. Similar corrosion mechanisms separate a zone into sub-zones that may be discontinuous. The sub-zones of similar corrosion mechanisms and corrosion potential will be influenced by historical operating, mitigative and preventive activities. Upsets, both planned and unplanned, the introduction of inhibitor or biocide treatment solutions, or the use of spheres or pigs to clean the line, will help distribute electrolytes downstream. The excavation priority of the sub-zones could be set by the risk of wall loss, with the most severe being investigated first.

5.2 Performing the Detailed Examination Process

Selection and examination of sites for detailed examination shall be based on the detailed examination process diagram as shown in Figure 2. Any deviation from this process must be technically justified by the operator and the reasons for the deviation documented.

An alternative to the detailed examination process as described in Figure 2 is to optimize the number of excavations required for WG-ICDA assessment by engineering analysis (e.g., probabilistic methods). The use of alternative approaches shall be technically justified by the operator and the methodology and assumptions documented.

While external corrosion can be mapped manually or with laser or similar tools on the exposed pipe, internal corrosion must be measured using ultrasonic scanning or x-ray techniques.

- Hand scans over a grid pattern or automatically moving ultrasonic inspection gauge can provide actual remaining wall thickness using the reflection from both internal and external surfaces.

- X-ray, through both walls of exposed pipe, can be used to measure the net wall thickness. Several exposures are needed to inspect the entire 360 degrees of the interior.

- Long Range Ultrasonic inspection (LRUT) on coal tar coated pipe can assess approximately 60 feet (or a joint and a half) into the soil from the soil interface at the end of the bell hole. Casing and less dampening coatings such a FBE can more than double the inspection distance. LRUT cannot yet distinguish internal from external corrosion reflectors.

5.2.1 A minimum of five digs are required. The two highest priority locations must be examined first. If immediate defects are discovered, then each of the next high level priority sites must be examined, in turn, until immediate defects are no longer found. Two consecutive locations of the medium risk priority must be found to have minimal internal corrosion to complete the assessment. A final location from a low priority sub-flow location serves as a validation (see 5.3).

5.2.1.1 If the pipe segment has only one flow regime, prioritization will be based on the possible remaining wall thickness and corrosion mechanisms.

5.2.1.2 If the flow regimes cannot be prioritized for corrosion threat, the prioritization will be based on the corrosion mechanisms, durations and other contributions to cumulative wall loss, not simply flow regime.

5.2.2 One of the following criteria shall be used for measurements to determine the presence of significant internal corrosion. These criteria are the basis for determining the number of required detailed examinations.

5.2.2.1 Internal corrosion metal loss is considered significant if the wall thickness cannot support the internal pressure based on ASME B31G. This criteria requires scheduled maintenance or repair under ASME B31.8S. WG-ICDA excavation sites may be considered active if the remaining wall thickness is less than 80% of specified nominal thickness (i.e., twice the nominal wall thickness rolling error allowed in API 5L[29]).

5.2.2.2 A pipeline-specific analysis may be performed to develop criteria for significant internal corrosion. The analysis might include consideration of previous metal loss, dormancy, years of pipeline service, and other factors that contribute to cumulative wall loss.

5.2.2.3 Significant corrosion may be defined with suitable documented engineering justification from alternative international standards.

5.2.3 Operators may perform additional validation examinations at their discretion on regions for which the detailed examination process has been completed.

5.2.4 When the detailed examination process identifies the existence of extensive or severe internal corrosion where it was not predicted, the operator shall return to the pre-assessment step and re-assess his program using results of the detailed examination process since the applicability of the applied WG-ICDA prioritization process is in question.

5.2.5 When performing the detailed examination step, the operator shall measure and record details of the wall thickness to a grid pattern sufficient to determine the axial length and width to a tolerance of twice the wall thickness (t) (i.e., +/- 2t) of those wall loss indications present. The length of the pipeline affected by water accumulation may be large in some situations, and care should be taken in selecting a suitable NDE procedure. Remaining wall-thickness values must be periodically recalibrated at the site.

5.2.6 Nondestructive testing methods used to determine the remaining wall of the pipe in corroded areas shall be performed in accordance with qualified written procedures and applicable international standards by individuals qualified by training and experience.

5.2.7 The pipeline operator shall calculate the remaining strength of locations where corrosion is found. Example methods for calculating the remaining strength include ASME B31G,[30] RSTRENG,[31] and DNV RP-F101[32].

5.2.8 The inspection procedures, detailed wall-thickness data, and strength calculations must be retained with the WG-ICDA records for the pipeline.

5.3 Other Facility Components

5.3.1 In some cases, drips or other facility components may serve as convenient WG-ICDA examination points (see 4.5.5).

5.3.2 If the fixture geometry restricts evaporation, it is possible for corrosion to be more severe inside the fixture, even when located in a low risk sub-flow section of pipe. Therefore, the pipeline operator shall examine at least one fixture where water can be trapped in a low priority sub-flow region. This may be used as a validation site.

5.4 Excavation and Inspection

5.4.1 The pipeline operator must use supplementary standards to perform corrosion detection and mitigation because these are not included in the scope of the WG-ICDA standard.

5.4.2 Once a site has been exposed and before it is back filled, the operator may install a corrosion monitoring device (e.g., coupon, electronic probe, ultrasonic sensor, electrical resistance matrix, etc.) that may allow an operator to benefit from long term monitoring in the locations most susceptible to corrosion (e.g., NACE A3T199: "Techniques for Monitoring Corrosion and Related Parameters in Field Applications") and confirm inspection intervals.

5.4.2.1 Coupons installed at arbitrary locations (e.g., beginning of pipeline) may ensure that corrosive materials have not entered that region of the pipeline but are not expected to represent the entire pipeline with corrosion that varies with location.

5.4.3 ILI tool or other assessment results for an upstream portion of pipe within a region may provide information that can be used to help assess the downstream condition of the pipeline where a pig cannot be run.

5.4.3.1 Because WG-ICDA predicts corrosion severity depending on the flow, corrosion and mitigation factors, any integrity verification should consider locations of minimum acceptable corrosion.

5.4.3.2 Use of ILI data for detailed assessment must be supplemented by excavation and inspection consistent with the high priority sites identified in the indirect examination step of WG-CDA.

5.4.4 If an operator utilizing WG-ICDA determines that the locations most susceptible to corrosion due to the presence of water are free from metal loss, then the integrity of these regions will have been assured relative to this internal corrosion threat. In this case, resources can be refocused on pipeline regions where corrosion is determined to be more likely.

Section 6: Post Assessment

6.1 Introduction

The objectives of the post-assessment step are to validate the process, assess the effectiveness of WG-ICDA and to determine re-assessment intervals.

6.2 Validation of the Process:

6.2.1 WG-ICDA is a continuous improvement process. Through successive WG-ICDA applications, a pipeline operator should be able to identify and address locations at which corrosion activity has occurred, is occurring, may occur and is unlikely to occur.

6.2.2 At least one additional direct examination shall be conducted at a site within a zone that was categorized to have medium corrosion severity to provide additional confirmation that the WG-ICDA process has been successful.

6.2.3 For initial WG-ICDA applications, a second additional direct examination is required for process validation. The direct examinations shall be conducted at a site within a zone that was categorized to have medium corrosion severity or low corrosion severity if no medium sub-flow locations exist.

6.3 Assessment of WG-ICDA Long Term Effectiveness

6.3.1 Effectiveness of the WG-ICDA process is determined by correlation between detected corrosion and the WG-ICDA prediction at those locations.

6.3.1.1 Operators must evaluate performance effectiveness of WG-ICDA and the process shall be documented.

6.3.1.2 Improvements as a result of this assessment are to be continually incorporated into future WG-ICDA integrity assessments.

6.3.2 If extensive corrosion is found throughout the pipeline or corrosion is found at areas that were determined to have no priority, the WG-ICDA procedure needs to be re-evaluated or other assessment methodologies need to be implemented.

6.4 Determination of Re-assessment Intervals

6.4.1 WG-ICDA re-assessment intervals may be periodically reviewed using one or more of the following methods:

6.4.1.1 Re-examine high risk sites at a prescribed frequency to determine or assess the deterioration rate (i.e., monitor the site for the remaining wall thickness on the actual pipe).

6.4.1.2 Install one or more corrosion monitoring devices at sites of predicted high risk based on flow-modeling results, and/or at other representative locations.

6.4.1.3 Apply a corrosion rate model tool based on operating conditions, flow regime, gas quality, liquid composition, corrosion mechanisms, mitigation, prevention, dormancy, and other key factors to determine a safe interval.

6.4.1.4 Perform laboratory testing on extracted fluids representative of operating conditions, gas quality, liquid composition, corrosion mechanisms and other key factors to determine corrosivity.

6.4.2 The selected method(s) of setting re-assessment intervals must be technically justified and validated by the operator.

The distribution and/or uncertainty of predicted corrosion rates must be considered.

6.4.3 If it can be demonstrated that the internal corrosion threat is unlikely, future internal corrosion direct assessment must periodically demonstrate that no electrolytes have entered the regions.

Section 7: WG-ICDA Records

7.1 Introduction

This section describes WG-ICDA records that document, in a clear, concise, and workable manner, data that are pertinent to pre-assessment, indirect examination, detailed examination, and post assessment. All decisions and supporting assessments must be documented. It is recommended that the records required by the standard be kept for the life of the pipeline.

7.2 Pre-Assessment Documentation

All pre-assessment step actions and decisions shall be recorded. They may include, but are not limited to, the following:

7.2.1 Data elements collected for the segment to be evaluated, in accordance with Table 1.

7.2.2 Methods and procedures used to integrate data collected to determine when indirect examination tools can and cannot be used.

7.2.3 Characteristics and boundaries of WG-ICDA regions.

7.3 Indirect Examination

All indirect Examination actions and decisions shall be recorded. These may include, but are not limited to, the following:

7.3.1 Geographically referenced locations of the beginning and ending point of each WG-ICDA region, zone and sub-zone, and each fixed point (monument) used for determining the accuracy of each measurement.

7.3.2 Procedures for determining accuracy of inclination profiles.

7.3.3 Methodology, including real and assumed data, used to identify and prioritize areas that may be susceptible to corrosion.

7.3.4 Data used to record or estimate flow, compositions, corrosion growth rates, operations, mitigation and prevention decisions.

7.4 Detailed Examinations

All detailed examination actions and decisions shall be recorded. These may include, but are not limited to, the following:

7.4.1 Data collected before and after excavation, including measured metal-loss corrosion geometries, techniques used and reported records.

7.4.2 Planned mitigation activities.

7.4.3 Descriptions of and reasons for any selections of additional sites, validation sites or re-prioritizations.

7.5 Post Assessment

All post-assessment actions and decisions shall be recorded. These may include, but are not limited to, the following:

7.5.1 Maintaining safety through remaining-life calculation results.

7.5.1.1 Maximum remaining flaw size determinations.

7.5.1.2 Corrosion growth rate determinations.

7.5.1.3 Method of estimating remaining life.

7.5.1.4 Results of remaining strength calculations.

7.5.2 Re-assessment intervals, including technical justification and operator's validation of selected method of re-assessment and any scheduled activities.

7.5.3 Criteria used to assess WG-ICDA effectiveness and results from assessments.

7.5.3.1 Criteria and metrics.

7.5.3.2 Data from periodic assessments.

7.5.4 Monitoring Records

7.5.5 Feedback and how results were incorporated for continuous improvement.

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Appendix A: Procedure to Rank the Overall Corrosivity of Sub-zones: An Example

The following procedure is recommended as an example for use in the WG ICDA methodology standard to prioritize the overall corrosivity of locations within a pipeline segment. Figure A.1 is a flow chart, schematically depicting the eight steps involved. The proposed procedure is an effective way of achieving prioritization and does not preclude other methodologies that can quantify and rank the overall corrosivity of pipeline sub-zone locations.

To reduce the subjectivity of using this standard, more precise guidance on how to use the methodology will be needed. A more detailed analysis of each major parameter driving corrosivity, such as flow, mitigation, upsets, etc. is needed in order to generate a matrix that will include all sub-factors and the effects of sub-factors on the parameter. If a relatively objective quantity/score or a quantitative relation can be developed for the above effect under different pipeline conditions, the resulting overall corrosivity will be less subjective.

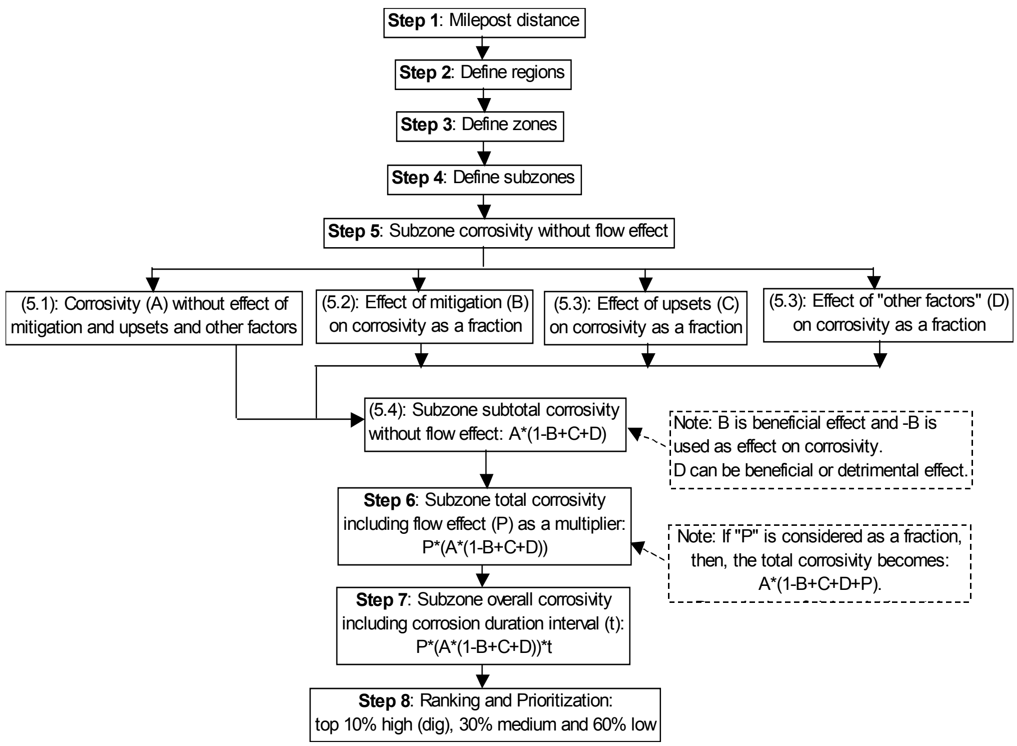

Figure A.1: A flow chart provided as an example to depict the eight steps for prioritization of sub-zones based on their overall corrosivity.

In developing the eight-step prioritization procedure as shown in Figure A.1, pipeline corrosivity is assumed to be affected broadly by six major parameters: pre-assessment, flow, corrosivity, mitigation, upsets and other factors. Historical record/data of design, construction, operations, conditions and experiences of a pipeline segment plays a vital role in determining the present corrosivity condition of the pipeline segment. Although it appears in this example that only the corrosion interval duration in Step 7 is derived from pre-assessment, the significance of pre-assessment is embedded in almost each step, and in particular, Step 5. The effects on corrosivity of the other five parameters would not be properly estimated if historical data were lacking.

Since the flow regime is used to divide a region into zones, in evaluating corrosivity within a zone, the flow effect can be neglected. A zone can be divided into sub-zones based on possibilities of the presence or absence of the four factors: corrosivity, mitigation, upsets and other factors. Thus, there are a total of 2^4 possibilities. Since half of the 16 possibilities would be absence of corrosivity, in the case of no water, for instance, these 8 possibilities can be treated as one sub-zone whose corrosivity is zero. As shown in Table A.1, there are no more than 9 types of sub-zones for any one zone.

In Table A.1, the simplest sub-zone is "S0". Without corrosivity in a region, the region is simply a zone and the zone is a sub-zone. The second simplest possible sub-zone is the one highlighted, or "S5", whose corrosivity should be relatively easy to estimate, which could in some cases be obtained by performing corrosion rate calculations or in other cases by expert's opinion.

By first neglecting the effect of mitigation upsets and other factors for each sub-zone, a value "A" as corrosivity can be either calculated or assigned in a scale range of 0-10, for instance, based on a comprehensive overall analysis of the corrosivity of all sub-zones within a pipeline segment including all regions. Then, the effect of mitigation, upsets and other factors on the corrosivity as a fraction to increase or decrease the corrosivity is assigned for each sub-zone. It is noted that in evaluating the instantaneous effect of upsets, or continuous but diminishing effect of mitigation with time, or the instantaneous or continuous effect of "other factors", the corrosivity duration interval of each sub-zone must be taken into account. For instance, for a sub-zone that experiences a long corrosivity duration, the effect of an upset on corrosivity might be relatively smaller than a sub-zone in which the corrosivity duration is short. The effect of mitigation along the segment length of a pipeline must also be considered since an inhibitor could be more effective upstream than downstream. With the above concepts considered, the eight-step procedure is described below.

Table A.1: A Matrix to Determine Sub-zones Based on Possibilities of Presence or Absence of Four Major Parameters

	A	B	C	D
Subzone	Corrosivity	Mitigation	Upsets	Other factors
S0:	n	/	/	/
S1:	y	y	n	n
S2:	y	y	y	n
S3:	y	y	n	y
S4:	y	y	y	y
S5:	**y**	**n**	**n**	**n**
S6:	y	n	y	n
S7:	y	n	n	y
S8:	y	n	y	y

Note: In this table, "y", "n" and "/"respectively represent "yes", "no" and "not applicable.

- In Step 1, the total milepost distance along the pipeline segment is listed as shown in the spreadsheet (Figure A.2, the following page). This shows the actual start and finish chainage along the pipeline. Other information is found in the columns to the right.

- In Step 2, wet gas ICDA **regions** are determined along the pipeline segment based on input, withdrawl, change of flow direction or other parameters as defined in the standard.

- In Step 3, flow regimes are determined for each region and each region is divided into **zones** based on flow regimes.

  There are broadly a total of four flow regimes and for each region. No more than five types of zones can be observed as shown in Table A.2.

Table A.2: Possible Types of Zones for WG ICDA

Zone	Flow Regime
Zone 0	No liquid
Zone 1	Mist
Zone 2	Stratified
Zone 3	Slug
Zone 4	Annular

- In Step 4, each zone is separated into a total of no more than 9 possible types of **sub-zones** based on Table A.1.

- In Step 5, the **total sub-zone corrosivity** is calculated before considering any effect of flow.

  Three sub-steps are required to accomplish this step.

  (1) Corrosivity (A): By accounting for all sub-zones within all regions of a pipeline segment of interest, a value A is assigned to corrosivity for each sub-zone within the scale of 0-10 or in any other range that an operator prefers. Note that this corrosivity term A neglects the effect of mitigation, upsets and "other factors" as each will be isolated and then considered in turn as the methodology proceeds through the following steps.

  (2) Mitigation (B) is expressed as a fraction in the range of 0-1, the effect of mitigation alone (B) for each sub-zone.

  (3) Upset (C) is expressed as a fraction in the range of 0-1, the effect of mitigation alone (C).

  (4) Other operational factors (D) also effects the above corrosivity in (1) and is numerically evaluated.

  Note that the effect of "other factors" can be beneficial, in which case the fraction is negative. For mitigation, B is positive, considered as a beneficial effect using the effectiveness of inhibitor or biocide. In assigning the fractions, the corrosivity duration for the specific sub-zone must be taken into account as described in the first paragraph of this appendix.

  (5) The subtotal corrosivity without including the effect of flow is calculated from: A*(1-B+C+D).

- In Step 6, the **total corrosivity including of the effect of flow** as a multiplier (P) to the subtotal corrosivity calculated in Step 5 is determined.

  The multiplier (P) must be scaled in consideration of all sub-zones within the pipeline segment. First, the scale is determined, for instance, in a range of 1-5 or an alternate range the operator prefers based on historical records or the expert's opinion. In this example, a scale of 1-5 is used. The total corrosivity accounting for the effect of flow is calculated from: P*A*(1-B+C+D).

- In Step 7, a **duration interval** (a) for each sub-zone is listed. With this duration as a multiplier to the total corrosivity calculated in Step 6, the **overall total corrosivity of a sub-zone** within the pipeline segment can be calculated from: P*A*(1-B+C+D)*t. If the operator believes that the duration is different for each of the factors A through D, then the time each influence has been present must be considered in the more appropriate way.

- In Step 8, the last step of the procedure, **rank** the overall total corrosivity calculated from Step 7 and prioritize digs. This **prioritization** can be done based on thresholds either predetermined by the operator or based on the following ranking: High = top ten percent; Medium = the next 30%; Low = the remaining 60%. This ranking is designated by different colors, respectively red, orange and green.

Total overall corrosivity of a subzone: S=P*(A*(1-B+C+D))*t

A is corrosivity due to gas quality without effects of upsets, mitigation or other factors.
B, C and D are in fraction respresenting effectivenss of mitigation, effects of upsets and other factors to corrosivity.
P is a multiplier as flow effects to corrosivity and t is corrosion duration interval for each subzone.

Step 1	Step 2	Step 3 (SubTable 1)	Step 4 (SubTable 2)	Step 5: 5.1 A	5.2 B	5.3 C	5.4 D	5.5 A*(1-B+C+D)
Mile Posts	Region	Flow Regime/Zone	Subzone	Corrosivity	Mitigation	Upsets	Other factors	Subtotal
1 2 3 4	Region 0	Zone 0	S0	0	/	/	/	*0*
5 6	Region 1	Zone 1	S4	10	0.8	0.3	0.2	*7*
7			S2	10	0.8	0.3	0	*5*
8		Zone 2	S4	10	0.6	0.2	0.2	*8*
9 10			S3	9	0.6	0	0.2	*5.4*
11 12		Zone 3	S4	8	0.3	0.1	-0.1	*5.6*
13 14 15			S8	10	0	0.2	-0.2	*12*
16	Region 2	Zone 4	S2	5	0.9	0.4	0	*2.5*
17 18			S4	7	0.7	0.1	0.2	*4.2*
19			S4	6	0.8	0.2	0.1	*3*
20 21		Zone 3	S4	3	0.5	0.1	-0.1	*1.5*
22 23			S1	8	0.4	0	0	*4.8*

Step 6: P	P*(A*(1-B+C+D))	Step 7:	P*(A*(1-B+C+D))*t	Step 8
Flow effect	Total corrosivity with flow effect	Duration t (year)	**Overall total corrosivity**	**Ranking/ prioritization**
	0	/	**0**	**[12]**
0.5	*3.5*	5	**17.5**	**[10]**
1	*5*	5	**25**	**[8]**
2	*16*	3	**48**	**[5]**
1.5	*8.1*	4	**32.4**	**[7]**
4	*22.4*	4	**89.6**	**[2]**
5	*60*	3	**180**	**[1]**
3	*7.5*	5	**37.5**	**[6]**
4	*16.8*	3	**50.4**	**[4]**
2	*16.8*	4	**67.2**	**[3]**
2	*3*	2	**6**	**[11]**
2	*9.6*	2	**19.2**	**[9]**

Figure A.2: Spreadsheet to demonstrate as an example how the eight-step sub-zone corrosivity-ranking procedure is implemented numerically. In performing the calculations, A is scaled in the range of 0-10; B represents the effectiveness of mitigation on a percent basis in the range of 0-100%; C and D are the effects of upsets and other operational factors on corrosivity, also on a percent basis in the range of 0-100% and (-100%)~(+100%), respectively. D is negative when the effect is reducing corrosion. P is a flow influence multiplier to corrosivity and scaled in the range of 1-5.

Appendix B: General Concept of Bayesian Updating

This appendix was requested by one of the NACE TC305 committee members. The addition of an appendix on Bayesian updating must ultimately be the decision of the whole committee after the necessary technical discussion. Others within the industry feel it should not be included, however, it is included here as a placeholder to ensure that the necessary discussions take place and to enable the NACE TC305 Committee come to resolve the issue. Further development of this appendix will commence upon positive decision of the Committee to include the technique.

Bayesian updating is an arithmetic manipulation of probability that can be used to provide an updated (posterior) estimate of a prior probability statement.

Appendix C: Description of Intrusive and Non-Intrusive Monitoring Systems

C.1 Intrusive Monitoring Devices

Intrusive monitoring devices require an access fitting for direct exposure to effluents flowing inside the pipeline. Installations require shutdown of operations if an access fitting does not exist. The intrusive devices must be flush mounted to prevent interference with pigging operations if such operations are deemed necessary. Retrieval or replacement of the monitoring device requires specialized high-pressure retrieval tools or shut down with depressurization. Unless specially configured, the inserted devices might not see the same flow regime for the pipe wall up or downstream. In order to provide adequate electrolyte coverage of the devices, a "water trap" is in many cases specially created at the monitoring site to allow water accumulation necessary for the device to function. The normal flow regime is not necessarily observed at the water trap. Intrusive monitoring devices include corrosion coupons, electrochemical probes and electrochemical resistance probes.

- Corrosion coupons
  Corrosion coupons are often used for corrosion monitoring because of their low cost and visual appearance. Coupons reflect the total corrosion response between insertion and retrieval dates but cannot provide information on when the most severe corrosion takes place. If the corrosion morphology is isolated pitting, there is a statistical chance that a corrosion coupon cannot detect it due to its limited physical size.

- Electrochemical probes
  An electrochemical probe measures the corrosivity of fluids, whether unmitigated or mitigated, as seen by the device, and counter and reference electrodes at monitoring locations. Sometimes, counter and reference electrodes are combined into a single electrode. The measurement methods of the probes include linear polarization resistance (LPR), electrochemical impedance spectroscopy (EIS or also known as AC Impedance), electrochemical noise, etc. In order for the measurements to be reliable and consistent, the probes must be fully immersed in an aqueous solution and should be free from interference from non-conducting liquid hydrocarbons or conductive iron sulfide deposits bridging the electrodes.

- Electrical resistance probes or ER probes
  ER probes use a sensing element by which the decreasing wall thickness corresponding to increasing electrical resistance can be measured with specialized electrical resistance circuitry. An ER probe does not need continuous coverage by an electrolyte, and is not subjected to interference from non-conductive liquid hydrocarbon liquids. Its accuracy can be affected slightly (from 10 to 20%) by conductive iron sulfides if the sensing element is thin. The presence of such conductive iron sulfide can be likened to adding a parallel conducting path to the electrical resistance circuitry. Simple ER probes cannot differentiate between general wall loss and pitting corrosion of the same volume of metal loss as the changes in electrical resistance for either corrosion morphologies will be nearly identical. Due to its small size, an ER probe might not even register isolated pitting on the sensing element.

C.2 Non-Intrusive Monitoring Devices

Non-intrusive monitoring devices can be installed on the external side of pipelines without a need for shutdown of the pipeline operation unless safety regulations require otherwise. These devices do not disturb the internal surface conditions or fluid flow. For most applications, the installation is long-term. For permanent applications, a bell hole is not required since the setup can be buried and data acquisition can be performed from above ground. Such devices include hydrogen patch probes, fiber optic sensors, field signature method inspection tools (FSM-IT), and others.

- Hydrogen patch probes

Hydrogen patch probes measure the hydrogen atom flux which diffuses through interior steel from the pipeline internal surface to external surface. As such, diffusion involves only atomic hydrogen; the measured flux is a fraction of hydrogen generated by cathodic reactions.

- Fiber optic sensors
  Fiber optic sensors can be rigidly bonded to the external pipeline surface. When internal corrosion results in wall thinning, the sensor length increases and can be measured by light interferometry.

- FSM-IT
  FSM-IT is composed of a geometric matrix of sensing pins that are permanently attached to the external pipe surface by spot welding. By passing a controlled current through the sensing matrix, an electrical field signature is established. The first signature is unique. With occurrence of internal corrosion or erosion, the electrical field is changed and can be detected by FSM-IT as a 'potential drop' across the matrix. Computer software is used to compare the new measurements against the original signature to produce metal loss values. The software can track metal losses over time, calculate corrosion rate and create three-dimensional plots to illustrate accumulated wall loss over the whole matrix.

  In terms of operating principles, FSM-IT is analogous to ER as it uses the same structure as the sensing element. For that reason, it should be referred as Electrical Resistance Matrix (ERM). FSM-IT monitors internal corrosion over a large area and can differentiate between general corrosion and isolated pitting, attributed to the matrix design where general corrosion affects all pin pair responses and pitting corrosion affects only nearby pin pairs.

Other non-destructive techniques (NDT) such as radiography and ultrasonics can also be used to evaluate the integrity of a pipeline and identify the locations where internal corrosion may have occurred at some time in the past and is occurring at present.

Appendix D: Critical Angle Flow Modeling Results[1]

For the case of dry gas ICDA[1], a critical angle was calculated as a function of flow rate, pipe diameter, and pressure. Below the sharp transition superficial gas velocity, the flow regime is predicted using comprehensive software to change from stratified flow to slug flow[33]. The results of the critical angle calculations were abstracted in terms of a modified Froude number for different pipeline inclination angle regimes denoted by:

$$F = \frac{\rho_l - \rho_g}{\rho_g} * \frac{g * d_{id}}{V_g^2} * \sin(\theta) \qquad \text{(D.1)}$$

where ρ_l and ρ_g are the liquid and gas density, respectively, g is the acceleration due to gravity, V_g is the superficial gas velocity (volumetric gas flow rate divided by the cross section area of the pipe), d_{id} is the internal diameter of the pipe, and θ is angle of inclination of the pipe in the gas flow direction. Based on a number of calculations performed, the Froude number was calculated for different pipeline inclination regimes:

$$\begin{aligned} &F = 0.36 \pm 0.08; \quad for\ \theta \le 0.5^\circ \\ &F = 0.33 + 0.143 \times (\theta - 0.5); \quad for\ 0.5 \le \theta \le 2^\circ \\ &F = 0.56 \pm 0.018; \quad for\ \theta \ge 2^\circ \end{aligned} \qquad \text{(D.2)}$$

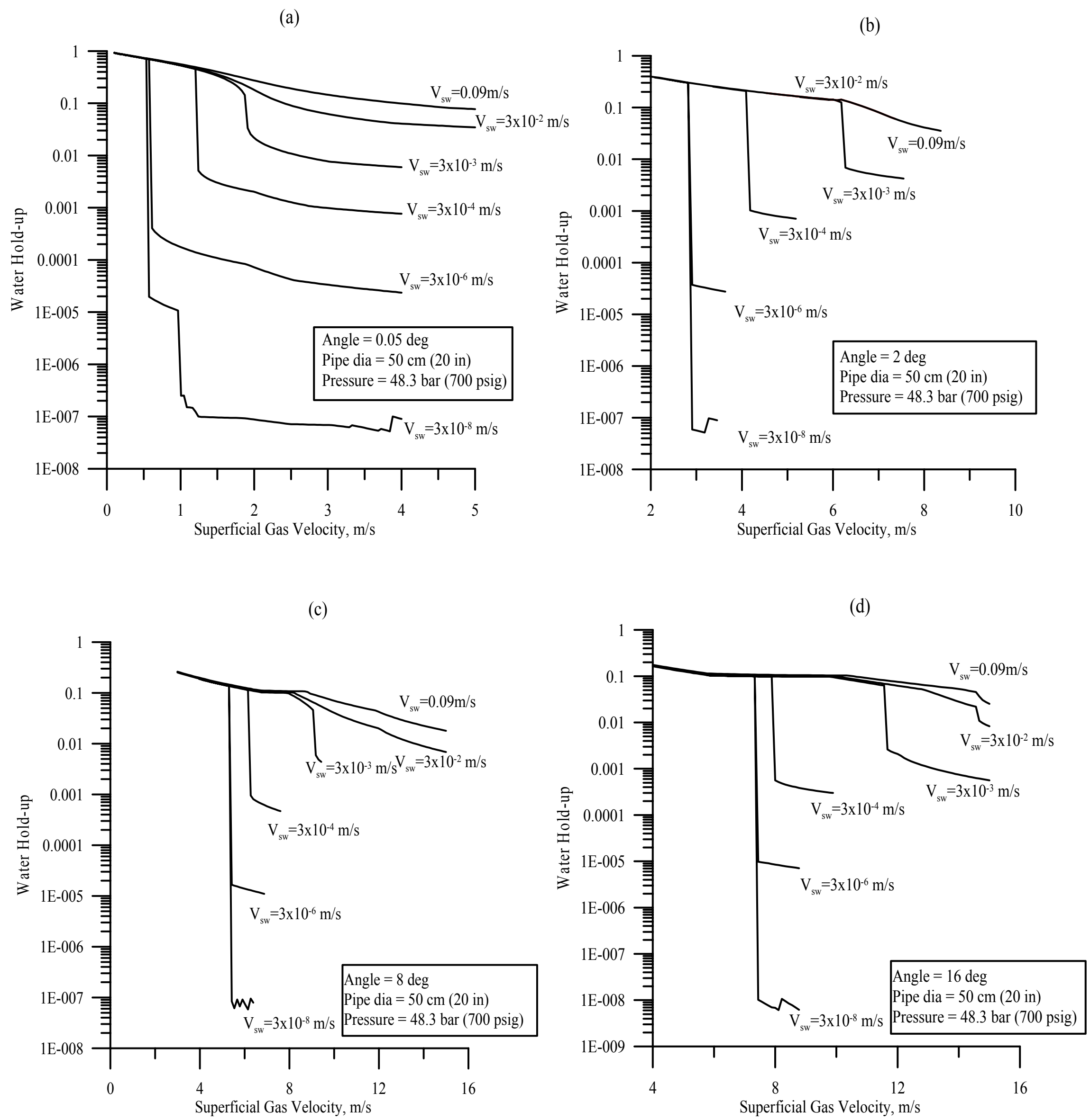

Figure D.1. Flow Modeling calculations of water hold-up fraction as a function of different water loading (as superficial water velocity) and pipe inclination angles.

It must be noted that the parameters in Eq. 2 consider flow calculations of pipeline diameters ranging from 10.2 cm (4 inch) to 122 cm (48 inch) O.D. and gas pressures ranging from 48 to 75 bars (700 to 1100 psi). In addition, the calculations assumed extremely low water content. Below the sharp transition superficial gas velocity, the flow regime is predicted to change from stratified flow to slug flow.

In order to explore the effects of water content of gas, further calculations were performed assuming different amounts of input water (Figure D.1). The water loading (input water) was varied by varying the superficial water velocity, which is defined as the volumetric flow rate of water divided by the total pipeline cross-section area. The ratio of superficial water velocity to the sum of superficial water and gas velocities is the fraction of water in the pipe. The water hold up, defined as the fraction of the cross-sectional area of the pipe occupied by water, was calculated as a function of superficial gas velocity (volumetric flow rate of gas divided by the total pipeline cross-sectional area) and angle of inclination of the pipe. The parameters that were held constant for these calculations were the total gas pressure 48 bars (700 psig), pipe internal diameter 48.9 cm (19.25 inches), and temperature 15.5°C (60°F).

As shown in Figure D.1, for low water loading [superficial water velocity less than about $3x10^{-3}$ m/s (0.01 ft/s)], there is a sharp transition in the fraction of water hold-up with gas velocity for any given pipeline inclination. Although these calculations show that the assumption of a critical angle is still valid up to a certain water fraction, it must be noted that a sufficient number of calculations have not been performed to establish whether the critical angles can be represented in terms of a Froude number as the water fraction increases. However, as the water loading is increased above about $3x10^{-2}$ m/s (0.1 ft/s), flow modeling calculations showed that that the sharp decrease in hold-up fraction does not occur. This means that there is no critical angle for water hold-up and the abstracted model used in the current ICDA procedure cannot be implemented. Full flow modeling has to be performed in such cases. Furthermore, the flow regimes become more complex.

For intermediate water contents, the critical angle concept can be used. However, the critical angle depends on the water content as shown in Figure D.2. In such a case, a probabilistic analysis using the range of critical angles may be performed, although the Froude number may not be a valid parameter.

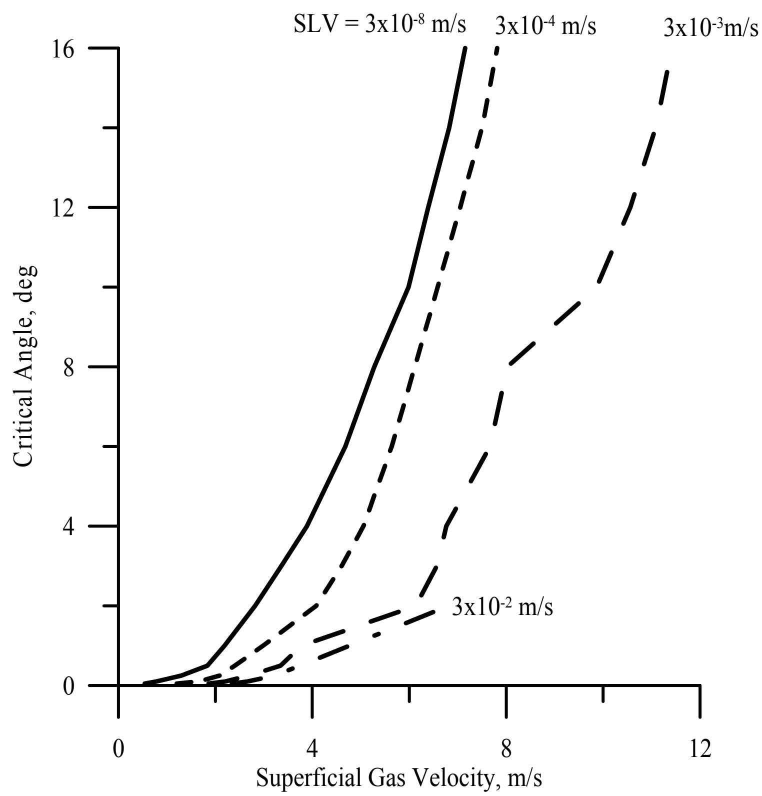

Figure D.2. Effect of different water content (as represented by the superficial liquid velocity, SLV) on the critical angle for a given gas velocity